Report prepared for:

The World Bank
Washington, D.C.

COST REDUCTION STUDY FOR SOLAR THERMAL POWER PLANTS

FINAL REPORT

May 5, 1999

Prepared by
Enermodal Engineering Limited
650 Riverbend Drive
Kitchener, ON N2K 3S2
Tel: 519-743-8777 Fax: 519-743-8778
e-mail: office@enermodal.com

in association with

Marbek Resource Consultants Ltd.
Suite 500, 1355 Bank St
Ottawa, Ontario

EXECUTIVE SUMMARY

Recent concern over the problem of climate change has generated renewed interest in Solar Thermal Power Plants (STPP) as a means of generating electricity. STPPs, although more expensive than conventional fossil-fuel power plants, release much less carbon dioxide and other pollutants. There are several applications for World Bank/GEF funding for STPPs in developing countries. The purpose of this report is:

- to assess the current and future cost competitiveness of STPPs with conventional power systems,
- to determine the market potential for STPP with particular emphasis on developing countries, and
- to identify an overall strategy for promoting accelerated development of STPP, including recommended roles for the key players (in particular the GEF).

The market for STPP is large and could reach an annual installation rate of 2000 MW. The best regions for STPP are Southern Africa, Mediterranean countries (including North Africa, Middle East and Southern Europe), India, parts of South America, Southwest U.S./northern Mexico and Australia. The operating characteristics of STPPs are relatively well matched with the intermediate and peak electricity load requirements in these regions.

Two types of collectors have been used in STPPs: parabolic trough and central receiver. Electricity is generated by incorporating the solar collectors with a Rankine cycle power plant or as an add-on to a natural gas combined cycle (referred to as an ISCCS). STPPs in southern California, with a total output of 354 MW, have operated reliably over the past 15 years.

New parabolic trough STPPs are estimated to have a capital cost (in developing countries) that is $2,000 to $3,000 per kilowatt or 2.5 to 3.5 times that of conventional Rankine-cycle plants. Central receiver STPPs are less mature than parabolic trough and will require several successful projects to scale up to reasonable sizes. The current costs of central receiver STPPs are close to $4,200 per kilowatt or five times that of conventional Rankine-cycle plants.

At the current state of technology development, the cost of solar-generated electricity is between 10 and 15 cents per kWh (at a 10% discount rate). This is two to four times more expensive than power from conventional power plants. Although solar power from ISCCS is 10% to 20% less expensive than for a similar sized Rankine-cycle STPP, it is competing against a much lower cost conventional power plant (combined-cycle).

Two approaches were used to predict the future cost performance of STPP: an engineering approach based on known technical improvements and cost reductions from commercialization and an experience curve approach. The two approaches yielded similar results. The cost-per-kilowatt of trough plants are expected to fall by 40% and central receiver systems are expected to fall by over 60%. The cost of electricity from conventional power plants is expected to stay constant over the next twenty years.

The solar Levelized Energy Cost (LEC) is expected to fall to less than half current values as a result of performance improvements and cost reductions. At these costs, the potential for STPPs to compete with Rankine cycle plants (coal, gas or oil fired) is promising. In the long-term, the LEC for Trough Rankine plants is expected to be within the cost range for conventional peaking plants. If a credit for reduced carbon emissions is included, all STPPs have a lower LEC than coal-fired Rankine plants. ISCCS plants are not expected to produce power that is less expensive than a gas-fired combined-cycle plant.

Given the promising results, a three-phase development plan is recommended to commercialize STPPs as summarized below. The three phases are market awareness, market expansion and market acceptance. GEF support is critical to the success of this plan.

Required Investment in STPPs by Phase[1]

Phase	Time Frame	Solar LEC Target (c/kWh)	Additonal Installed Capacity	Est. Total Incremental Investment ($ million)	Est. GEF Investment ($ million)
Phase 1	2000 – 2004	10 to 11	750 MW	440 to 750	350 to 700
Phase 2	2005 – 2009	7 to 8	3000 MW	500 to 1,800	250 to 900
Phase 3	2010 +	Under 6	4600 MW	0 to 330[1]	0 to 150[1]
Total			**8300 MW**	**940 to 2,955**	**600 to 1,750**

[1] – assumes a carbon market develops by Phase 3

In Phase 1, the GEF would need to provide financial support in the order of $350 to 700 million to fund approximately nine projects. The support would be in the range of $550 to $1000/kW.

In Phase 2, a further 3,000 MW of installed capacity would be supported. The total support cost is estimated at $500 million to $1.8 billion ($350 to 750/kW). Additional financial partners are expected to emerge, so that GEF support would only be a portion of these values.

In Phase 3, the emergence of carbon credits could mean that STPPs are cost effective and only modest financial support is required (under $330 million). The total support required to commercialize STPPs is estimated at between $1 and $3 billion; approximately 60% of which would need to come from the GEF. The annual GEF investment is estimated at between $60 and $160 million.

The success of the commercialization will depend on several factors. First and most importantly is whether the cost and performance goals for STPPs are met. The goals are 10 to 11 cents/kWh at the end of Phase 1, 7 to 8 cents/kWh at the end of Phase 2 and under 6 cents in Phase 3. Second, cost parity is based on a financial credit for reduced carbon emissions. If there is no carbon trading, carbon credits or carbon tax, the adoption of STPPs will be reduced or slowed. Third, trade, tax and other economic barriers must not penalize the solar option. Real-life financing issues can have a major impact on the adoption of any technology. The study was performed as an economic analysis, not a financial analysis.

The GEF can play a major role in all three of these factors, ensuring that a cost-effective technology is developed, a program of carbon credits or trading is implemented and financial barriers are limited.

ACKNOWLEDGEMENTS

This report was prepared by Enermodal Engineering Limited (Stephen Carpenter and Stephen Kemp) and Marbek Resources Consultants Ltd. (Paul Robillard and Sean Whittaker) for the World Bank. The authors would like to acknowledge the assistance and guidance of World Bank staff (Richard Spencer, Charles Feinstein and Rohan Singh) throughout this project. The technical support of SunLab (National Renewable Energy Laboratory and Sandia National Laboratories) staff (Tom Williams, Hank Price and Greg Kolb) was critical to the preparation of this report. Finally, the authors would like to thank the numerous industry members who provided a critical review of the project through its various stages.

DISCLAIMER

Table of Contents

List of Figures

List of Tables

PREFACE

There is a growing demand for electricity in developing countries. The conventional approach to meet this need is through the construction of fossil-fuel power plants. The operation of these plants, however, releases carbon dioxide and contributes to the problem of climate change. Furthermore, many of these countries rely on imports for their energy needs and the purchase of fossil fuel weakens their financial position.

Many developing countries have an abundance of a natural energy source: solar radiation. Operation of solar thermal power plants (STPP) would reduce their reliance on fossil fuels. Regions that could make use of these systems include Southern Africa, Mediterranean countries (including North Africa, Middle East and Southern Europe), India, Northern Mexico and parts of South America. The developed regions of Southwest U.S. and Australia could also benefit from this technology. Several commercial STPPs are currently operating in the U.S. although no new plants have been constructed in the last eight years.

There are two types of collectors used in STPP systems that are at or close to the commercialization stage: parabolic trough and central receiver. Although several systems using parabolic trough collectors have been built, they are at an early stage in their deployment and their installed cost is high relative to fossil-fuel power plants. Several variants of the central receiver have been built largely as demonstration projects.

OBJECTIVES

The purpose of this study is to assess whether STPPs can achieve cost parity with conventional power plants. Cost parity is assumed to be achieved when the costs of the STPP and conventional system are equal taking into account capital, O & M, fuel usage and differing performance. The work plan to achieve this end has three main components:

- to assess the current and future cost competitiveness of STPPs with conventional power systems,
- to determine the market potential for STPP with particular emphasis on developing countries, and
- to identify an overall strategy for promoting accelerated development of STPP, including recommended roles for the key players (in particular the GEF).

METHODOLOGY

This project has been conducted in two parts. They are:

Part A - Situation Assessment

Part B - Strategy and Implementation Plan

The Part A Situation Assessment addresses the current context confronting STPPs. This necessarily addresses such important considerations as technology configuration, installation and operation costs, performance efficiency and, estimated market potential. In addition to examining and reporting current status, the Situation Assessment also draws on a combination of engineering, empirical and literature resources in order to present a set of baseline forecasts of expected future STPP cost and performance data. These baseline future STPP cost and performance forecasts are then contrasted with those for comparable conventional utility power generation systems. The comparison of baseline forecasts provides a basis for estimating the magnitude of the investment (and related conditions) that are required to reach parity with the expected future costs of conventional power generation technologies.

The second part of the study focuses on a development plan for closing the gap identified in Part A. This part of the study examines preferred roles for international organizations such as the World Bank and The Global Environment Facility (GEF), together with expected total levels of investment required to achieve the objective of cost parity. The implementation strategy also identifies possible exit strategies for the GEF.

This study was conducted within a relatively short time frame because of the need to respond to current requests for World Bank funding of several STPPs. Given the time constraints and magnitude of the project scope, the study team relied on the technical expertise of SunLab personnel and several recent reports on STPPs in assessing the cost and performance of STPPs. Thus, for the most part this report is a “due diligence” assessment of STPPs rather than original research.

PART A

SITUATION ASSESSMENT

1. SOLAR THERMAL TECHNOLOGIES: OVERVIEW

1.1 INTRODUCTION

The solar thermal power plants (STPPs) that are addressed in this study consist of two major components: a solar collector that converts solar radiation into thermal heat and a power conversion system that converts the heat into electricity. There is a variety of solar and power conversion technologies that can be combined in different ways (including the addition of thermal storage) to produce electricity. To ensure consistent use of terminology, this section begins with a brief definition of the technology terms as they are used throughout this report. This is followed by a brief description of the solar collector and power generation technologies that are assessed in this study. A brief description of solar storage systems is also provided. The section concludes with an overview of future STPP developments.

1.2 DEFINITIONS

1.2.1 Plant Description

In describing a given plant configuration, it is important to use a standard nomenclature to avoid confusion between the various STPP options. The term “SEGS” (Solar Electric Generation Station) has traditionally been a generic term relating to the parabolic trough technologies that employed the Rankine cycle with 75% solar and 25% fossil fuel input. The parabolic trough STPPs installed in California by Luz International are termed SEGS I through IX. For this report, the term SEGS refers only to these installations.

In this report, the designation for a given STPP will be of this form:

<Nominal power (net)> <Power conversion system> <Solar collector type> [Options: Storage, Time frame]

For fossil-fuel power plants, the <*Solar collector type*> is replaced with the fuel type. A brief discussion of each term is given below:

Nominal Power:
This is the maximum gross power that the power plant can produce using solar energy or fossil fuel energy. For hybrid systems (systems that operate on solar and fossil fuel at the same time) only the solar power output is listed, given in megawatts (MW).

Power Conversion:
Thermal energy from a power source is converted to electrical energy in a power conversion system consisting of one or more turbines. For the purposes of this study, two power conversion systems are examined: Rankine cycle and Combined Cycle systems.

Solar Collector Type:
A solar collector is used to concentrate solar radiation onto a receiver where heat transfer to a fluid takes place. In this study, two concentrating solar thermal collection technologies are examined: parabolic troughs (or "troughs") and solar central receivers (often termed "power towers").

Fuel Type:
This refers to the type of fossil fuel consumed in the non-solar part of the power plant. If the power conversion equipment is a Rankine cycle, then fuels such as natural gas, coal (scrubbed) and fuel oil no. 2 may be used. In the case of a Combined Cycle system, natural gas is the preferred fuel.

Options:
These options may apply to any type of plant. *Storage* refers to a system that allows for the storage of excess thermal energy from the STPPs solar collector. This energy can then be used during periods when solar insolation is reduced (cloudy periods or at night).

Example
A typical designation may look like this: 30 MW ISCCS -Trough

This designates a STPP with 30 MW nominal power, parabolic trough concentrating solar thermal collectors, and an Integrated Solar Combined Cycle System power conversion configuration. In this case, it is assumed that no thermal storage is involved and that the fuel used is natural gas.

1.2.2 Plant Operation Definitions

Heat Collection Efficiency: The percentage of the incident solar radiation that is converted to usable heat by the solar collector

Power Cycle Efficiency: The percentage of the thermal energy that is converted electrical energy (gross)

Parasitic Efficiency: The conversion from gross efficiency to net efficiency accounting for losses from parasitic electric power to operate the plant and losses from start-up and part load operation (assumed to be 5%).

Solar-to-Electric Net Efficiency: The net operating efficiency of the plant, or the percent of the incident solar radiation that is converted to electricity for the grid

Annual Solar Efficiency: The Solar-to-Electric Net Efficiency on an annual basis accounting for plant downtime (5%) and below optimum performance (5%).

Plant Capacity Factor: The annual electricity output divided by the maximum plant output or the percentage of the time the plant is operating (at full load)

Solar Capacity Factor: The annual electricity output provided by solar energy divided by the maximum plant output or the percentage of the time the plant is operating (at full load) on solar. The ratio of the solar capacity factor to the plant capacity factor is the fraction of the plant output provided by solar energy.

1.3 SOLAR COLLECTOR TYPES

The solar collector is the first major component of the STPP. This report focuses on parabolic troughs and central receivers because they are judged to be the only solar thermal technologies that can make a significant contribution to the electrical grid in the near to medium-term (to 2010). Furthermore, troughs and towers are designed for large-scale grid applications, whereas other solar technologies such as solar dishes are better suited to distributed small-scale application.

1.3.1 Parabolic Troughs

Parabolic troughs consist of long parallel rows of reflectors (typically, glass mirrors) that are curved to form a trough. At the focal point of the reflector is the absorber tube or receiver. The receiver is a pipe treated with a low-e coating encased in a glass cylinder, the space between the pipe and glass cover is evacuated. The rows are arranged along a north-south axis and they rotate from east to west over each day. Parabolic troughs can achieve concentration ratios (ratio of solar flux on the receiver to that on the mirrors) of between 10 and 100.

A heat transfer fluid or HTF (typically, an oil) is circulated through the receiver to remove the solar heat. The HTF can be heated to temperatures of up to 400^{o}C. The fluid is pumped to a heat exchanger where its heat is transferred to water or steam. The parabolic trough can collect up to 60% of the incident solar radiation and has achieved a peak electrical conversion efficiency of 20% (net electricity generation to incident solar radiation).

Nine trough systems were constructed in the 1980s and are currently generating 354 MW of electricity in Southern California. Three types of collectors were used over this period, however, the basic size and construction are similar. The troughs are approximately 5 meters wide in rows up to 100 meters long. See Section 3.2 for a more complete description of these plants.

Figure 1.1 Trough Principle *(courtesy of Pilkington Solar International)*

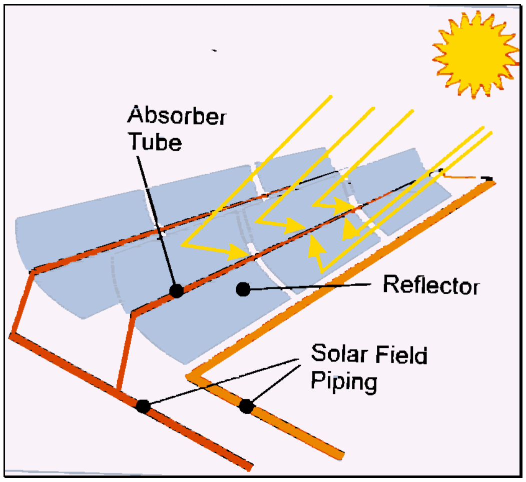
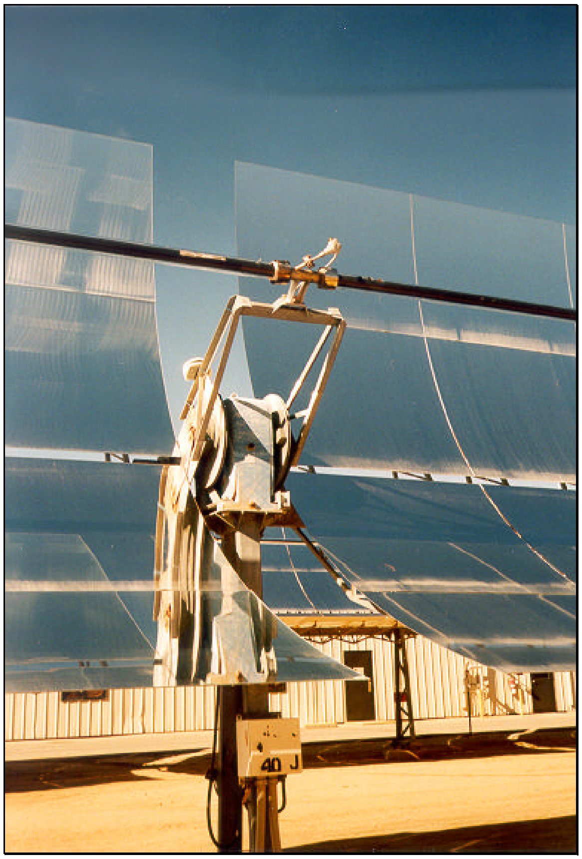


Figure 1.2 Trough Drive Mechanism



1.3.2 Central Receivers

Central receivers, or power towers, consist of a central tower surrounded by a large array of mirrors or heliostats. The heliostats are flat mirrors that track the sun on two axes (east to west and up and down). The heliostats reflect the sun's rays onto the central receiver. The sun's energy is transferred to a fluid: water, air, liquid metal and molten salt have been used. This fluid is then pumped to a heat exchanger or directly to a turbine generator.

Central receivers can achieve higher concentration ratios (800) and therefore higher delivery temperatures than parabolic troughs (up to 565^{o}C). The solar collection efficiency is approximately 46% and the peak electrical conversion efficiency (i.e., conversion from solar radiation to electricity) is 23%.

Several Central receiver demonstration projects have been constructed around the world and one commercial plant was built in Southern California: Solar One. Solar One was recently modified and is now referred to as Solar Two. For more information on these systems see Section 3.3.

Figure 1.3 Tower Principle

(courtesy of Pilkington Solar International)

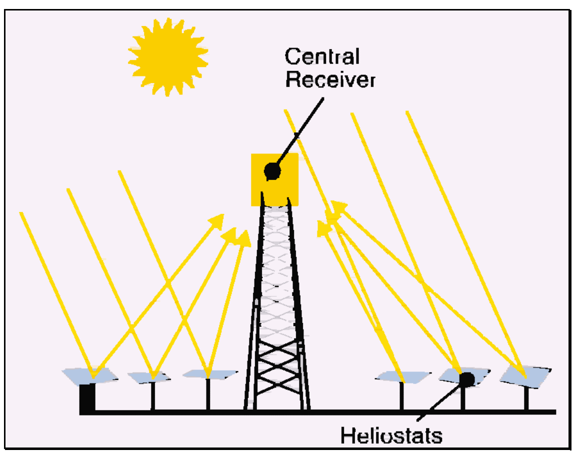


Figure 1.4 Heliostat at Solar Two Power Plant

1.4 SOLAR THERMAL POWER CONVERSION SYSTEMS

The second major component of the STPP is the power conversion system that is used to convert the heat into electricity. Two technologies are considered in this study:

- Rankine-Cycle STPP
- Integrated Solar Combined-Cycle Systems (ISCCS) and other hybrid systems.

To date, all STPPs have been Rankine-cycle systems. Rankine-cycle plants are a mature technology that offers a high solar contribution. Recently, integrating the solar collector system with a gas-fired combined-cycle system has been proposed as a lower cost alternative for generating solar-powered electricity.

1.4.1 Rankine-Cycle Systems

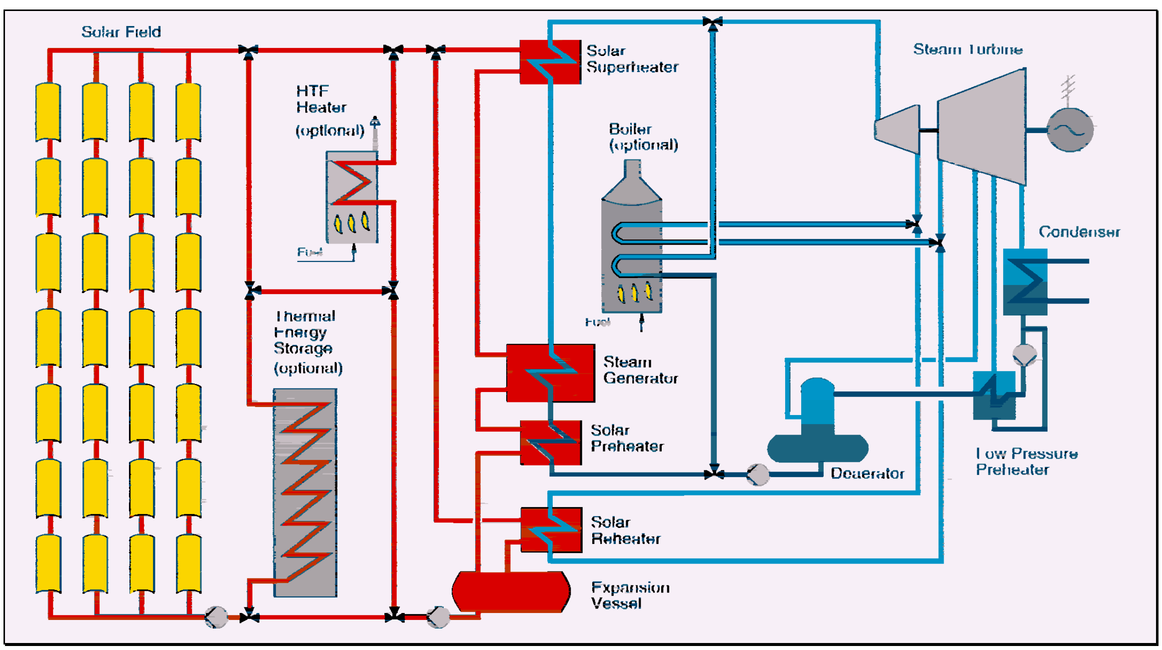
The Rankine-cycle STPP is a steam-based power plant with solar energy as the heat source. The system is a typical Rankine cycle (see Figure 1.3). The hot collector heat transfer fluid transfers its heat in the heat exchanger to the water/steam. The steam drives the turbine to produce electricity. The spent steam is condensed into water in the condenser. The water is re-heated in the heat exchanger and the cycle repeats.

Because of the seasonal and daily variation in solar radiation, a Rankine-cycle system can only be expected to operate at full load for approximately 2400 hours annually (25% capacity factor) without the use of thermal storage. In most cases, it makes sense to add a fossil-fuel heater so that the system can operate at full load for more hours. SEGS are usually designed so that the plant can operate at full load on fossil fuel alone. Back-up fuels can be coal, oil, naphtha and natural gas.

The number of hours a plant operates will depend on local conditions. In most cases, however, it makes sense to operate this type of plant to meet the daily periods of high demand for electricity (10 to 12 hours per day).

Rankine-cycle systems suffer from relatively low efficiencies (whether solar or fossil-fuel powered). The conversion of heat to electricity has an efficiency of about 40%. If the conversion efficiency from fossil fuel to heat is included, the plant efficiency drops to approximately 35%.

Figure 1.5 Rankine-Cycle STPP *(courtesy of Pilkington Solar International)*



1.4.2 Integrated Solar Combined Cycle Systems

Combined cycle natural gas systems are becoming a popular electricity generation system in areas where natural gas is available. A combined cycle plant uses a gas combustion turbine as the first stage in electricity generation. The hot flue gases from the turbine pass through a heat exchanger (Heat Recovery Steam Generator) to generate steam. The steam drives a steam turbine as the second stage in the electricity production process. Combined cycle systems have heat-to-electricity efficiencies of approximately 55%.

Solar energy can be integrated into the second stage of this process. These systems are referred to as Integrated Solar Combined Cycle Systems (ISCCS) (see Figure 1.4). ISCCS differ from the Rankine-cycle systems in that the solar components are an add-on to a conventional power plant, sometimes referred to as a solar boost. Solar heat can either generate additional steam in the Heat Recovery Steam Generator (option A) or can generate low-pressure steam to be injected directly into the steam turbine (option B). In either case, the capacity of the steam turbine is increased over that in a conventional combined cycle to handle the additional solar-generated steam.

At peak output, the solar system accounts for 20 to 30% of combined cycle output. Thus, the solar systems can boost the output of a 100 MW combined cycle plant to 130 MW. On an annual basis, the solar contribution drops to approximately 10%. It is important to note that the solar system does not generate electricity by itself; it is designed to operate as a power boost when the gas turbine is running. In addition, the system must be well designed so that the performance of the combined cycle does not suffer when solar heat is unavailable.

ISCCS offers two main advantages over other power plants. First, the peak capacity of the power can be increased at a lower capital cost than other power plants because the main incremental cost (other than for the solar field) is for a larger steam turbine. Second, the integration of a solar system with a combined cycle boosts power often when it is needed most. Conventional combined cycle systems suffer a reduction in plant output when the outdoor temperature is high. The lower density of the air reduces the mass flow through the gas turbine and therefore reduces its output. Generally, the solar system has its peak output in early afternoon when the outdoor temperature is highest.

A second method of integrating a solar system with a gas turbine plant has been proposed. In this system, referred to as a Solar Energy Enhanced Combustion Turbine (SEECOT^{TM}), the heat from the solar system is used to drive an absorption cooling system (see Figure 1.5). The cooling system cools the gas turbine inlet air, thereby increasing its efficiency. This approach overcomes the problem described in the previous paragraph. In addition, the solar generated steam can be mixed with the gas to increase the mass flow rate and output of the turbine.

The net effect is that the increase in turbine output is many times larger than the energy required to generate the steam and to cool the air. The developers of the system attribute this benefit to the solar system, whereas it is really a result of the mechanical cooling system that could be driven by any energy source. Many utilities have recognized this benefit and mechanically cool the inlet air to the turbine (albeit with conventional power not solar energy).

Figure 1.6 Integrated Solar/Combined Cycle System

(courtesy of Pilkington Solar International)

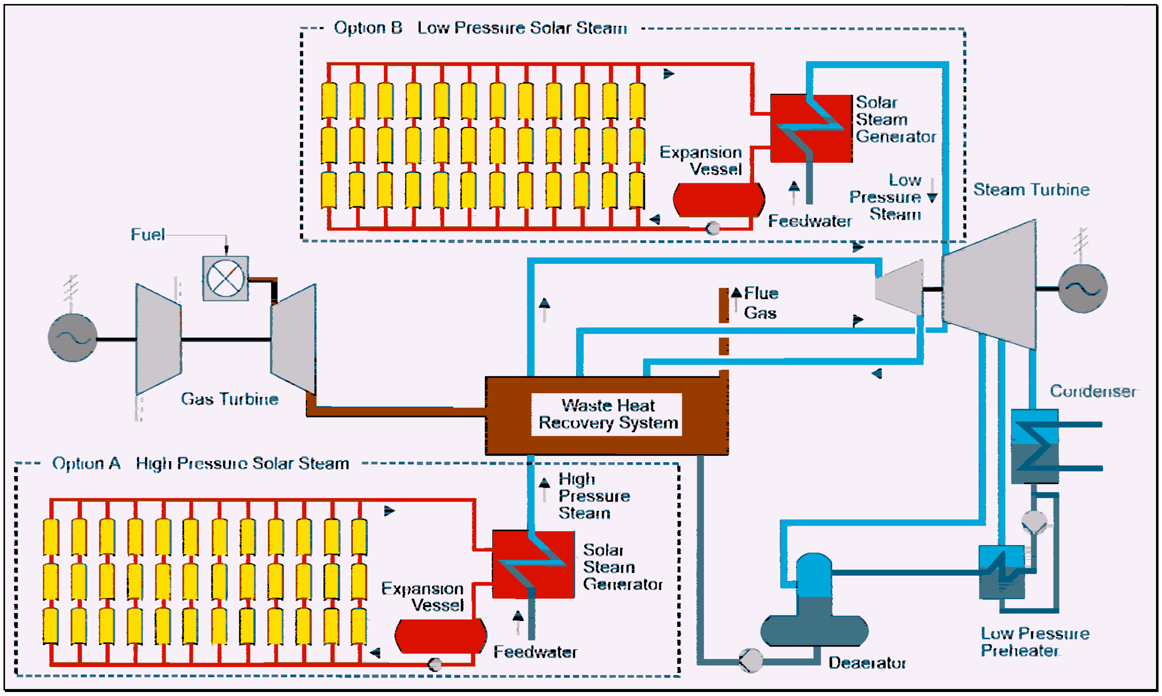
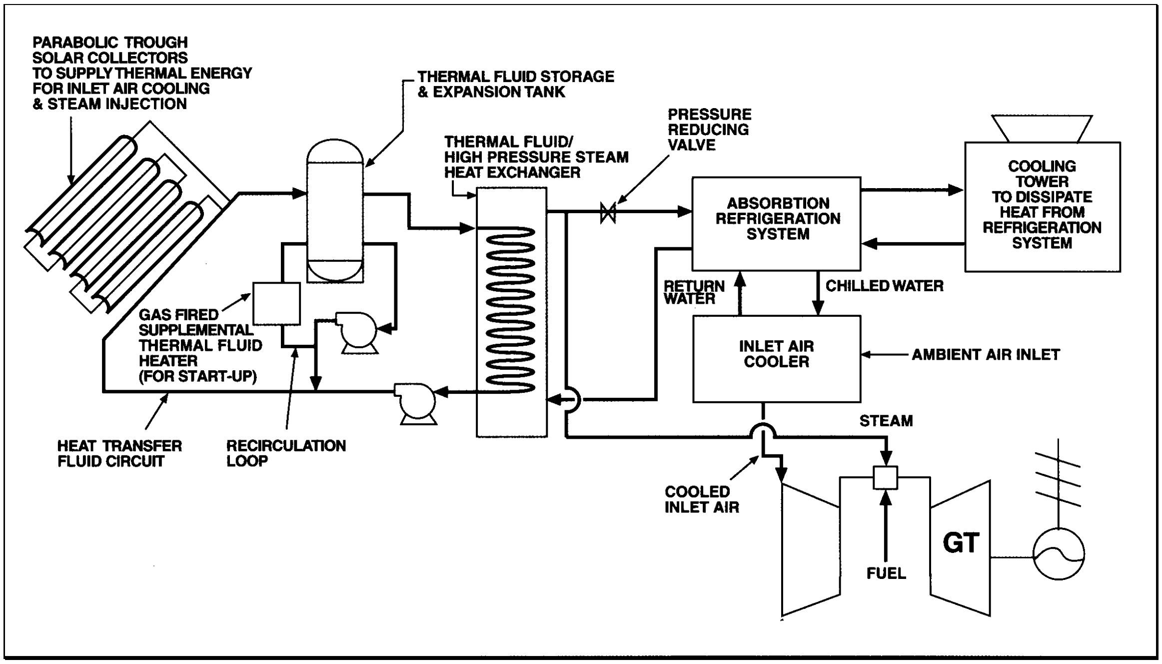


Figure 1.7 Solar Energy Enhanced Combustion Turbine
(courtesy of York Research Corporation)



1.4.3 Hybrid Solar/Rankine-Cycle Generation Systems

Solar generated steam can also be integrated into a conventional Rankine-cycle power plant in similar manner to Option B of the ISCCS. The turbine in the Rankine cycle plant is oversized to handle the steam produced by the solar system. Similarly, high-pressure steam from the solar system could be fed into the main steam generator to supplement its output (similar to Option A of the ISCCS). Since many Rankine-cycle plants use coal as the fuel source, these hybrid options have the advantage of achieving proportionately greater reductions in plant emissions.

1.5 THERMAL STORAGE DEVICES

Although thermal storage has not been used in most solar thermal power plants built to date, it does offer four important benefits. First, thermal storage can shift the output of the STPP to later in the day when demand for electricity is highest. A shift of three to six hours is typically required for the output of the STPP to match the utility demand. Second, thermal storage increases the dispatchability of the power plant. Power can be delivered whenever there is a peak in the utility demand for electricity.

Third, thermal storage can increase the solar capacity factor of the plant. Capacity factor is the ratio of the actual annual plant output to the maximum plant output (i.e., a plant running at full output 100% of the time). In systems without storage, the annual solar capacity factor is limited to approximately 25%. The size of the solar field can be increased and thermal storage added to increase the annual solar capacity factor to over 50%. Fourth, increasing the solar capacity factor means that the fossil-fuel components of the power plant can be eliminated, making it no longer necessary for the plant to be close to a source of fuel.

The first parabolic trough system in the U.S. used two large hot and cold storage tanks to provide three hours of thermal storage. The collector heat transfer fluid was also the heat storage fluid. This system is, however, restricted to low operating temperatures (307^{o}C). The HTF in the higher temperature parabolic trough systems is too expensive to serve as the heat storage medium. A suitable storage medium has yet to be proven but systems using concrete and steel have been proposed.

The higher temperatures in central receiver systems allow molten nitrate salt to act as both the HTF and the storage material (as used in the Solar Two plant). Molten nitrate salt is low-cost, stable and non-toxic.

1.6 FUTURE SOLAR GRID-CONNECTED TECHNOLOGIES

There are several solar thermal technologies that are at the research stage and worthy of mention. Two of the most promising technologies are solar dishes and photovoltaics. A solar dish is a parabolic dish with a heat engine located at the focal point. The heat engine uses Stirling or Brayton cycles to produce power within the dish. Peak electrical efficiencies of up to 30% have been achieved. Photovoltaics or solar cells convert sunlight directly into electricity and are commonly used to supply electricity for off-grid applications. Commercial solar cells have electrical conversion efficiencies of up to 16%, although most operate at closer to 10% efficiency.

Currently, these systems produce power that is at least three time more expensive than parabolic trough systems [DOE/EPRI, 1997]. The DOE/EPRI study projected that with technological advances these systems may be able to produce power at a lower cost by the year 2030.

Two more-speculative technologies are solar chimneys and solar ponds. The solar chimney consists of a large glazed area with a chimney in the middle. Air under the glazing is heated by the sun and rises up the chimney. A wind turbine in the chimney converts this motion into electricity. In a solar pond, layers of water with increasing salt content fill a shallow pond. The sun's rays are absorbed in the lower layers of the pond. The temperature gradient between the upper and lower layers of the pond drives a heat engine. Both of these systems are simple and relatively low cost. Their primary disadvantage is low solar conversion efficiency (under 1%).

1.7 SUMMARY

The preceding discussion illustrates that there are a number of solar technologies that are currently in operation, while additional technologies remain under development. Regardless of which solar technologies eventually prove to be the most cost-effective, it is widely felt that the cost of solar generated electricity can be expected to decline in the longer term due to technological advances, volume production, competitive pricing through international tenders and increased efficiencies in construction practices.[1] Table 1.1 lists the STPPs and the conventional power plants examined in this study. These plants cover the major systems options described in this section for the near-term, medium-term and long-term.

Table 1.1 STPP Cases Examined in This Study

Case	Power Plant	Time Frame
1	400 MW Coal-fired Rankine Cycle	Near-Term
2	376 MW Gas-fired Combined Cycle	Near-Term
3	30 MW Trough – Rankine Cycle	Near-Term
4	200 MW Trough – Rankine Cycle	Near-Term
5	30 MW Trough - ISCCS	Near-Term
6	30 MW Central Receiver – Rankine Cycle	Near-Term
7	30 MW Central Receiver - ISCCS	Near-Term
8	100 MW Trough - ISCCS	Medium-Term
9	200 MW Trough - Rankine	Medium-Term
10	200 MW Trough - Rankine	Long-Term
11	200 MW Trough – Rankine with storage	Long-Term
12	100 MW Central Receiver – ISCCS with storage	Medium-Term
13	100 MW Central Receiver – Rankine with storage	Medium-Term
14	100 MW C. R. – Hybrid Rankine with storage	Medium-Term
15	200 MW Central Receiver – Rankine with storage	Long-Term

[1] Spencer Management Services, correspondence, Feb 15, 1999.

2. THE MARKET FOR STPP

2.1 INTRODUCTION

The second important consideration addressed by this study is whether there is sufficient market potential to fully support the increased scale of STPP production that would be required to achieve price parity with conventional electricity generation options. As such, this section briefly identifies suitable market regions for STPPs together with forecast rates of growth in electricity demand. Solar-generated electricity is available only during daylight hours (although with storage it can be available into the evening to provide a better match to the utility load curve). Therefore, this section also provides a review of typical electricity load curves in the candidate regions and comments on the compatibility of the STPPs with local loads.

2.2 SUITABLE REGIONS FOR STPP

Concentrating solar collectors, such as parabolic troughs and central receivers, can only concentrate direct solar radiation (as opposed to diffuse solar radiation). Thus, STPP will only perform well in very sunny locations, specifically the arid and semi-arid regions of the world. Although the tropics can have high solar radiation, the high diffuse solar radiation and long rainy seasons make these regions less desirable for STPP. Figure 2.1 shows the promising regions for STPP. These regions can be divided into six geographic areas:

- Southern Africa,
- Mediterranean countries (including North Africa, Middle East and Southern Europe),
- Parts of India and Pakistan,
- Parts of Brazil and Chile,
- Mexico and southwest U.S., and
- Australia.

With the exception of the Southern Europe, Southwest U.S. and Australia, the countries in these regions could qualify for World Bank/GEF support.

Suitable regions for STPP should have annual solar radiation values of at least 1700 kWh per square meter. The best sites for STPP have solar radiation values in excess of 2700 kWh per square meter. Table 2.1 lists the available solar radiation in some of the regions being considered for STPP. (Jordan weather data was used in this study because it is a reliable set of data from a country reasonably close to several projects under consideration.)

Figure 2.1 Suitable Regions for STPP

(courtesy of Pilkington Solar International)

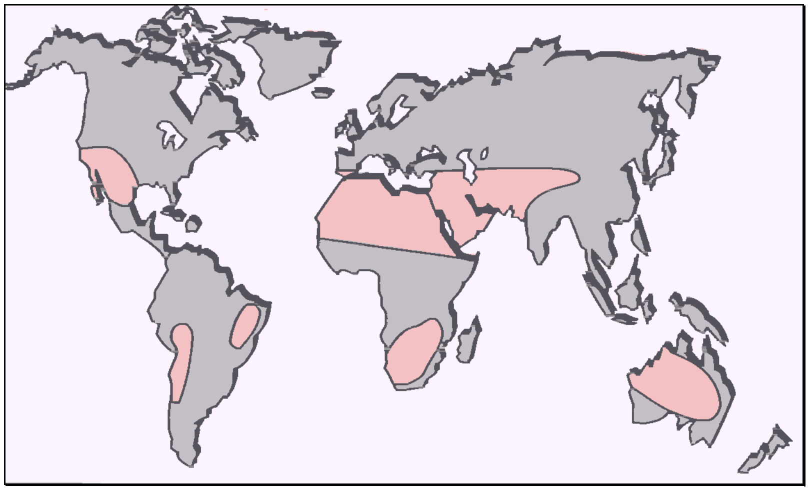


Table 2.1 Annual Solar Radiation Values in Locations Suitable for STPP

Location	Site Latitude	Annual Direct Normal Insolation
Barstow, California	35 °N	2,725
Northern Mexico	26-30 °N	2,835
Wadi Rum, Jordan	30 °N	2,700
Ouarzazate, Morocco	31 °N	2,364
Crete	35 °N	2,293
Jodhpur, India	26 °N	2,200

2.3 POTENTIAL MARKET FOR STPP

The demand for electricity in developing countries is growing at a fast pace. For example, Egypt is planning to increase its electrical capacity by 50% over the next eight years [International Private Power, 1998]. The potential worldwide market for STPPs over the next 20 years is estimated at 600 GW or 6000 plants of 100 MW solar capacity [Pilkington, 1996], most of this in developing countries. However, STPPs have a higher capital cost than conventional power plants. The initial market penetration for STPPs will be for those niche applications of high fuel costs or restricted access to fuel. Over the next 20 years Pilkington predicted actual installations of 45 GW or over twenty 100 MW solar capacity plants per year, assuming niche markets could allow for a 7.5% penetration rate. These figures show a huge potential for STPP. As is discussed in later sections of this report, the actual penetration rate will depend on progress in reducing the cost/performance ratio, support from governments (and the GEF), and energy prices.

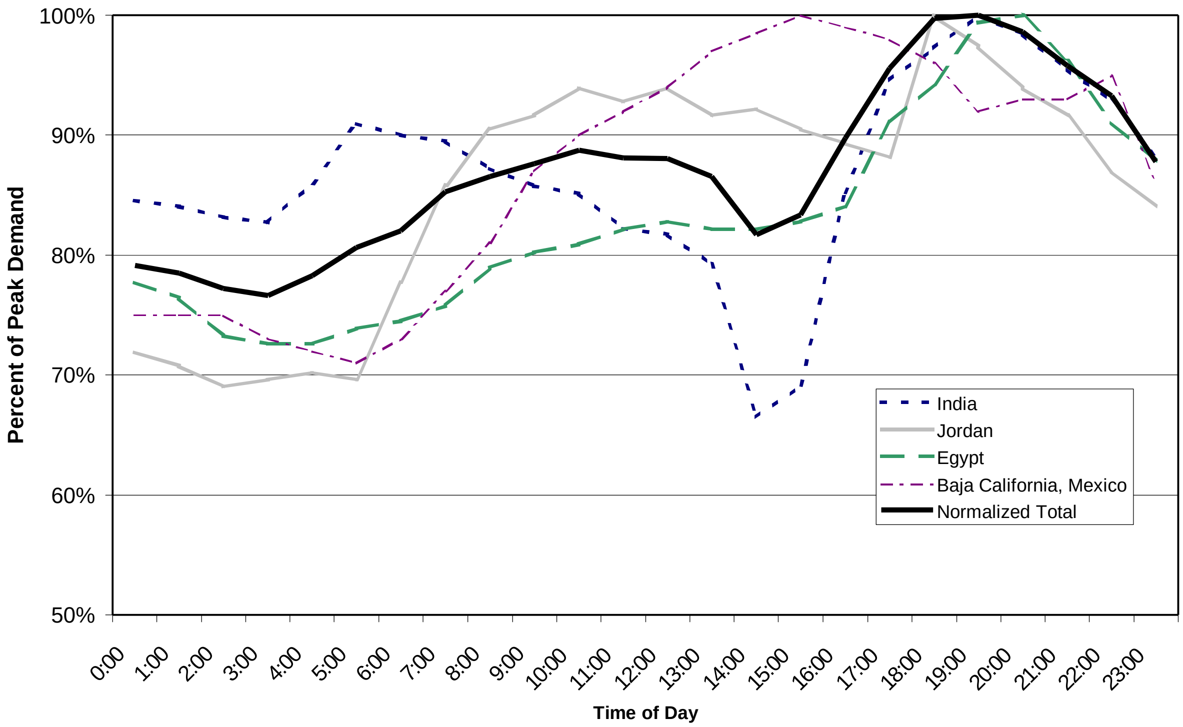
2.4 ELECTRICITY GENERATION IN DEVELOPING COUNTRIES

It is necessary to understand the electricity market in a country to properly design a STPP for that country. The type and operation of electricity generation stations will depend on the fuels available and the daily and seasonal usage profile. For the regions where STPP are being considered (arid and semi-arid), hydro-electricity is likely not available or has been fully exploited. Fuel options for power plants (in the typical order of priority) are natural gas, coal, oil and naphtha. Where natural gas is available, it is usually the fuel of choice for power plants. It is low cost and has the lowest emissions when burned. Combined cycle natural gas power plants are commonly used because they can achieve fuel-to-electricity conversion efficiencies of over 50%. Where plants are required to operate only a few hours a year or portions of the year (i.e., as a peaking plant), lower capital cost (and efficiency) gas turbines are used. Coal-fired Rankine cycle plants offer the benefits of large capacity and use of the lowest cost fuel. They suffer from low operating efficiencies (approximately 35%) and the highest emissions.

Figure 2.2 shows the daily utility load profiles for four developing countries: India, Jordan, Egypt and Mexico. The values for India are the average of three regions. With the exception of India, all the countries show a similar profile. The base load period is about 75% of the peak and runs from about 11:00 p.m. to 8:00 a.m. The intermediate load runs from 8:00 a.m. to 5:00 p.m. and the peak load from 5:00 p.m. to 11:00 p.m.

The shape and time of the peak does however, vary significantly between the countries. Using the same terminology and definitions as Anderson [1998], some utilities have a “spiky” peak of 4 to 5 hours per day (e.g., Egypt), whereas others have a “flat” peak of 10 or more hours per day (e.g., Jordan). The time of the peak depends on the utility customer base and amount of air-conditioning used. As more air-conditioning is added the peak shifts to earlier in the afternoon (see Mexico) which is more favorable for solar generation. In India, local demand for electricity is highly dependent on the customer type. Utilities serving primarily residential customers have a peak demand in the evening, whereas utilities serving primarily industrial customers have a profile that follows business hours.

Figure 2.2 Utility Daily Demand Curves



Utilities typically use a mix of power plant types to meet the demand profile for electricity. Table 2.2 lists the plants and their typical operating hours per year. (Some plants may have operating hours between two categories and, as such, are a hybrid of the two types.) Large, low operating cost plants will run continuously to meet the base load (e.g., coal-fired Rankine cycle). The highest operating cost plants will be reserved to operate only five hours per day to meet the "spiky" peak demand. Plants to meet peak loads include older and generally less efficient Rankine cycle plants and gas or diesel turbine plants. Intermediate cost plants will be used to meet the intermediate peak or flat-peak demand. Combined-cycle plants are often used to meet intermediate loads because they are efficient and can be easily cycled.

Table 2.2 Typical Operating Hours for Conventional Power Plants

Type of plant	Operating hours per year
Base Load	Over 8000
Intermediate	4000 to 4400
Flat Peak	2000 to 2200
Spiky Peak	under 1000

Solar Thermal Power Plants provide both energy and capacity benefits for peak and intermediate loads. STPPs could reduce base load capacity but would require large thermal storage and economically is not as favorable because of the low operating cost of base load plants. Because solar power is available 8 to 12 hours per day, it would not be used just to displace “spiky” peak power for a few hours a day. Rather the STPP would operate at least as long as solar power is available. Thus, the cost of power produced by STPPs should be compared to the cost of power from conventional plants operated between 2200 and 4400 hours per year (25 to 50% capacity factor).

The range in conventional power plant operating hours results in different costs for electricity generation. A plant that operates for short periods of time has fewer hours over which to amortize the capital and fixed operating costs. Analyzing a range in power plant capacity factors (25 and 50%) introduces a high and low cost of conventional power. The determination of appropriate values is discussed in Sections 3.4 and 5.1.

2.5 SUMMARY

The preceding discussion indicates that there is a large potential load for STPP and, the operating characteristics of STPPs are relatively well matched with the intermediate and peak electricity load requirements in the identified regions. As the market matures, an annual rate of installation of 2000 MW is achievable.

3. STPP COST & PERFORMANCE EXPERIENCE TO DATE

3.1 INTRODUCTION

The preceding sections have provided an overview of the current STPP technologies and have confirmed that the potential market size is sufficiently large to support large-scale deployment, provided that cost and performance requirements can be met.

This section provides a summary of the STPP installation and operating experience to date. A brief historical background is provided for each technology, together with a summary of installation and operating costs. Accumulated experience related to other key operating considerations, such as capacity factors, reliability, etc., are also reported from the available literature sources. Comparable data is also provided for the two conventional power plants that serve as the study's baseline. The information in this section provides the basis for the inputs into the calculation of levelized energy costs that are presented in the next section.

3.2 PARABOLIC TROUGH STPP

3.2.1 Background

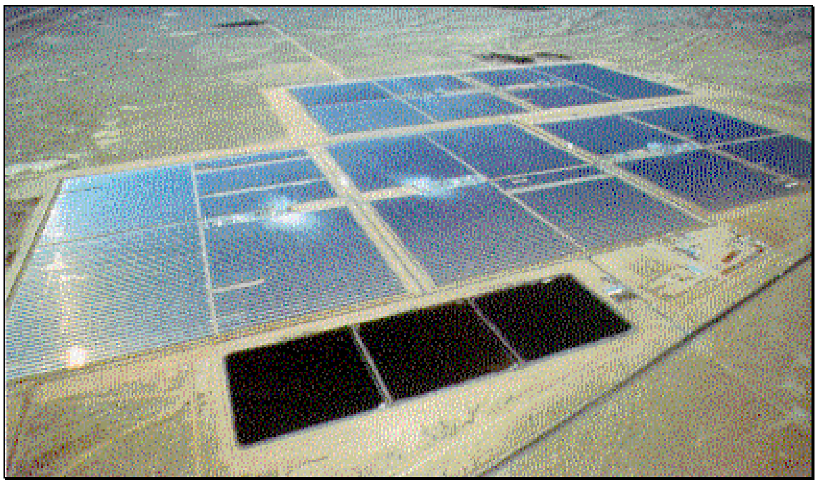
Parabolic trough STPPs are the most mature of the solar thermal power plants. Between 1984 and 1991, Luz International Ltd. constructed nine Rankine-cycle SEGS plants in the Mojave Desert of southern California. The details of these plants are summarized in Table 3.1. The first plant included a large thermal storage reservoir and no back-up heat source. The remaining eight plants use natural gas as the back-up heating fuel to a maximum of 25% of the energy input (as limited by U.S. federal law to qualify as a solar plant). No storage was used. Luz designed, built, supplied the collectors and operated the plants. The power was sold to Southern California Edison (SCE) under a long-term contract. The size, performance and efficiency increased with each successive plant. Similarly, the cost per kilowatt fell with each plant. The cost of power production from these plants fell by almost 60% over this time period.

Luz filed for bankruptcy in 1991 primarily because of the reduction in solar credits from the government and declining energy prices. Following the failure of the Luz Corporation, the plants have continued to operate for upwards of 15 years demonstrating the reliability of the technology. The plants have consistently exceeded their design capacity during the utility peak summer period.

The five plants SEGS III to VII (see Figure 3.1) are operated by the Kramer Junction Company and are still achieving 93% of the annual expected output [pers. comm. Henry Price, NREL]. The primary reason for degradation is the loss of vacuum and breakage of the Heat Collection Elements. KJC estimate the breakage rate at 3% per year. Correction of design problems are expected to reduce this breakage rate.

Figure 3.1 Aerial View of the SEGS III-VII Plants at Kramer Junction

(courtesy of Pilkington Solar International)



No other commercial parabolic trough STPPs have been built since the Luz projects. However, the combination of technology improvements and financial support to reduce greenhouse gas emissions from various agencies has brought several projects to the feasibility stage, particularly in those countries that lack indigenous sources of energy.

Table 3.1 Characteristics of the Luz SEGS Plants

Unit	I	II	III	IV	V	VI	VII	VIII	IX
Capacity, Net MW	13.8	30	30	30	30	30	30	80	80
Land Area, *hectares (approx.)*	29	67	80	80	87	66	68	162	169
Solar Field Aperture Area, *hectares*	8.3	19.0	23.0	23.0	25.1	18.8	19.4	46.4	48.4
Solar Field Outlet Temperature, °*C*	307	321	349	349	349	391	391	391	391
Annual Performance (design values)									
Solar Field Thermal Efficiency, *%*	35	43	43	43	43	43	43	53	50
Solar-to-Net Electric Efficiency, *%*	9.3	10.7	10.2	10.2	10.2	12.4	12.3	14.0	13.6
Net Electricity Production, *GWh/yr.*	30.1	80.5	91.3	91.3	99.2	90.9	92.6	252.8	256.1
Unit Cost, *$/kW*	4,490	3,200	3,600	3,730	4,130	3,870	3,870	2,890	3,440

3.2.2 Parabolic Trough - Systems Assessed in This Study

Two parabolic trough STPPs are examined: Rankine-cycle and ISCCS. ISCCS are generally seen as the “market entry” system for STPPs. They have a low solar capacity and therefore low incremental cost and risk. There are several ISCCS proposed for developing countries (with support requested from the GEF), typically a 100 MW combined cycle plant with a 30 MW solar boost. In the future, the size of this plant could be increased to 350 MW with a 100 MW solar boost.

In the longer term, as the costs of STPP decrease, there will be a desire to increase the solar capacity beyond the 10% achievable with ISCCS. Rankine-cycle will become the preferred system. Two sizes of SEGS systems are examined. The cost and performance of a 30 MW plant is studied so that a direct comparison can be made to the ISCCS plants. The preferred size of Rankine cycle SEGS is 200 MW. At this size, most of the economies of scale have been achieved. Although this size is larger than previous SEGS plants, there is no technical reason this size cannot be constructed. The 80 MW size of the Luz plants was a restriction imposed by the U.S. government. Luz had investigated plant sizes to 160 MW.

Table 3.2 Details of Parabolic Trough STPP

	Rankine-cycle STPP	Rankine STPP with Storage	ISCCS
Solar Field ('000 m^2)	1210/1151/1046	1939	183 / 575 / -
Storage (hours)	0	12	0
Solar Capacity (MW)	200[1]	- / - / 200	30 / 100 / -
Total Capacity (MW)	200	200	130 / 450 / -
Solar Capacity Factor(%)	25 %	50 %	6 %Total, 26% Solar
Total Capacity Factor (%)	50 %	50 %	50 %

[1] – a 30 MW plant is also analyzed to compare to other STPP

[2] – multiple values are listed if value is different in near-term, medium-term, and long-term scenarios

3.2.3 Parabolic Trough - System Cost & Performance

Cost and performance estimates have been made for the current status of three parabolic trough systems. These estimates were based on information provided by SunLab and other recently completed assessments of STPPs. The cost estimates were made for the U.S. (where there is the greatest experience with these systems) and then adjusted for developing countries. These estimates are summarized in Tables 3.3 and 3.4.

The SEGS systems constructed in southern California provides useful experience on the cost and performance of parabolic trough systems (see Table 3.1). The design values for solar-to-net electric efficiency increased from 9.3% to 14.0% from 1984 to 1991. The annual performance values are lower than the solar-to-net electric efficiency because of losses due to power plant availability and cycling. The actual operating efficiency was 10 to 15% - lower primarily because of HCE breakage. Performance values similar to the most recent SEGS plants have been assumed for the current performance.

The cost of parabolic trough plants has fallen over the past 15 years. The cost of the SEGS plants in California fell from $4500/kW to just under $3000/kW between 1984 and 1991 (in current $). Based on this experience and cost reductions achieved in the intervening years, the current capital cost is estimated at $3495/kW for a 30 MW plant and $2435/kW for a 200 MW plant. The range in these two prices shows the large impact of system size on capital cost. These values are for a plant constructed in the U.S.

Figure 3.2 shows the estimated costs of parabolic trough plants from recently completed feasibility studies (Table 3.5) and a line representing the estimated cost for plants in the U.S. The costs for Rankine STPPs range from $2200/kW to $3400/kW. All of these plants appear to be slightly lower in cost than the U.S. values for the same capacity. The percentage reduction is not a constant. Spencer Management Associates, 1994 found that because of lower labor costs, the cost of a STPP was 19% cheaper in Mexico than in the U.S. Other cases showed higher and lower reductions. The average difference between the U.S. costs and those from the feasibility studies for developing countries was close to 15%. In this report, a 15% discount has been applied to the U.S.-based costs to estimate the cost of all STPPs constructed in developing countries.

The same costing methodology was used to estimate the solar portion of the ISCCS and the Rankine STPP, so that these two system types can be compared directly. The costs in Table 3.4 for the ISCCS are for the incremental solar portion. The total plant cost for this system is estimated at $1080/kW in the U.S. If this total ISCCS cost is reduced by 15% to $918/kW, it is comparable to the results of the 1998 Morocco study ($877). The costs for the Mexico study are higher but they do not reflect the recent reduction in conventional combined cycle costs.

The operation and maintenance costs for the complex of SEGS III to VII are currently running between 3 and 3.5 cents per kWh [pers. com. Mr. S. Frier, KJC, 1999]. The O & M costs on a per kilowatt-hour basis are high at these plants because of their small size (30 MW) and the relatively high failure rate of the HCE. SunLab estimates that O & M costs for a new design of 30 MW plant would be a third lower at 1.9 cents/kWh. O & M costs for one 200 MW plant would be lower still (at 1.1 cents per kWh) because the same number of operators can be used for this larger plant.

Annual O & M costs for STPP have been estimated at 0.7 to 1.1 cents/kWh in Mexico [Spencer Management Associates, 1994] and 1.0 cents/kWh in Jordan [Geyer, 1997]. These values are slightly lower than the values given in Table 3.4, again suggesting that costs are lower in developing countries. Accordingly, the O & M costs listed in Table 3.4 are reduced by 15% for the analysis of developing country projects in this report.

Table 3.3 Estimated Current Performance of Parabolic Trough STPP

Component	30 MW Trough - Rankine	200 MW Trough – Rankine	30 MW ISCCS (130 MW Total)
	Case 3	**Case 4**	**Case 5**
Heat Collection Efficiency	44.2%	44.2%	44.2%
Power Cycle Efficiency	37.5%	38.0%	38.0%
Parasitic Efficiency	83.6%	85.5%	90.2%
Solar-to-Electric Net Eff.	13.9%	14.4%	15.1%
Annual Solar Efficiency	12.5%	13.0%	13.7%
Plant Capacity	50%	50%	50%
Solar Capacity	25.0%	25.1%	26.0%

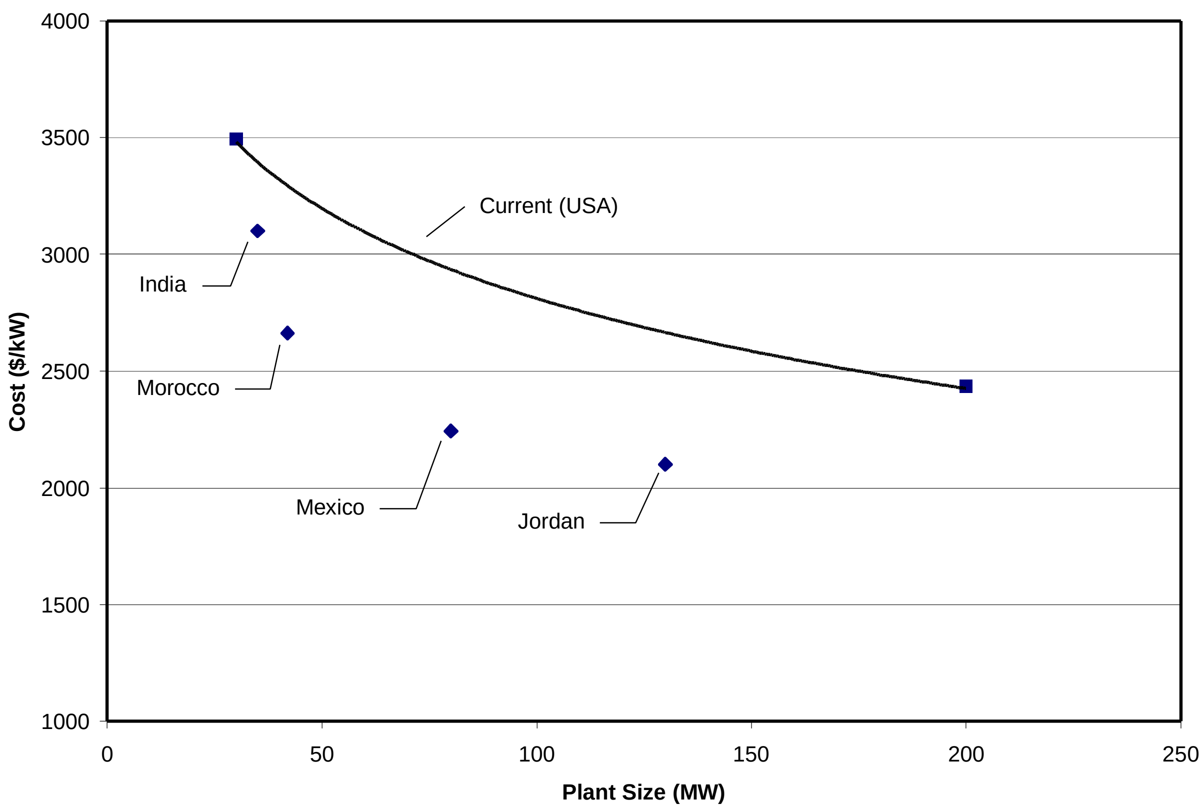
Table 3.4 Estimated Current Cost of Parabolic Trough STPP (in $/kW total plant output)

Component	30 MW Rankine STPP	200 MW Rankine STPP	30 MW ISCCS (130 MW Total)
Site Works	158	57	156
Solar Field	1534	1184	1467
HTF System/Boiler	282	234	134
Power Block	493	279	247
Balance of Plant	287	162	287
Services	275	192	244
Land	11	10	10
Contingency	454	316	402
Total (U.S. plant)	3495	2384	3093
Discount in Developing Countries	-524	-365	-464
Total	2971	2026	2629
O & M Cost (¢/kWh)	2.3	1.1	1.15

Table 3.5 Cost of Parabolic Trough STPP as listed in Recent Feasibility Studies

Location	Type	System Capacity (MW)	Cost ($/kW)	Reference
Orazibita, Mexico	Rankine	80 MW	$2244/kW	Spencer Management Associates, 1994
Jordan	Rankine	130 MW	$2100/kW	Geyer, 1997
Rajasthan, India	Rankine	35 MW	$3100/kW	Pilkington, 1996
Morocco	Rankine	42 MW	$2662/kW	Pilkington, 1998
Orazibita, Mexico	ISCCS	128 MW	$1498/kW (total plant)	Spencer Management Associates, 1994
Morocco	ISCCS	196 MW	$877/kW (total plant)	Pilkington, 1998

Figure 3.2 Current Estimates of Rankine-Cycle Solar Plant Specific Cost



3.3 CENTRAL RECEIVER SYSTEMS

3.3.1 Background

Although solar central receivers are less commercially mature than parabolic trough systems, approximately 10 solar central receiver systems have been constructed throughout the world. Most of these plants are research or proof-of-concept plants of only 1 to 2 MW. Solar One in southern California was planned as a commercial project but at 10 MW, this project was really a pilot demonstration system.

Solar One was built in 1981 and operated from 1982 to 1988. The plant used 1818 heliostats to reflect sunlight onto a central receiver. Water was converted into steam and used to drive a 10 MW turbine. The heat from the solar-heated steam could also be stored in a storage tank filled with rocks and sand using oil as the heat transfer fluid. The stored heat was used to generate power for up to four hours after sunset.

This project proved the technical feasibility of the central receiver concept. The system also had high reliability with 96% availability during sunlight hours. The system did however, suffer from low annual efficiency (only a 7% heat-to-electricity efficiency) and intermittent turbine operation caused by transient clouds.

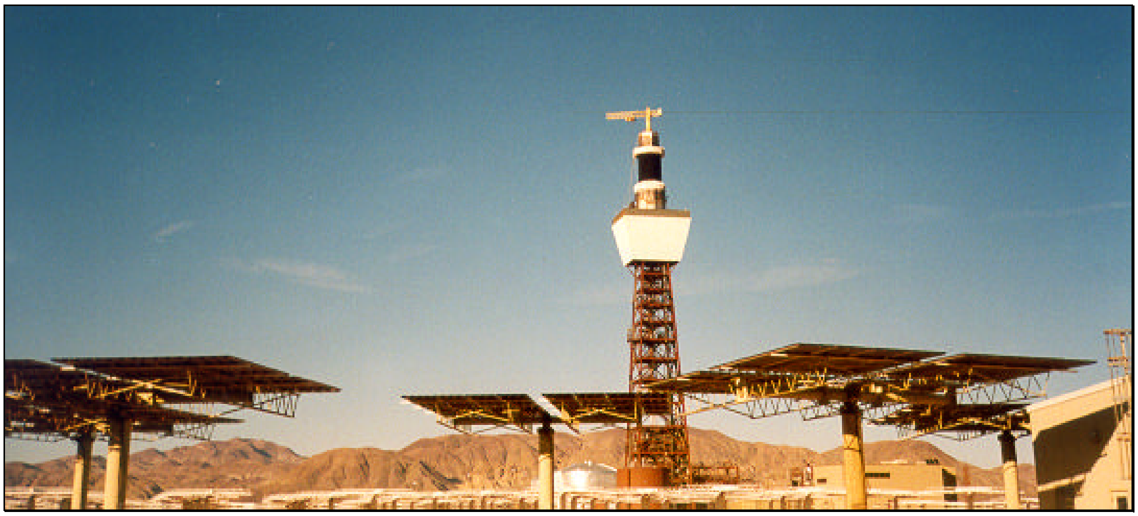
Solar One was redesigned in the early 1990's to overcome its limitations. The system HTF was converted from water/steam to molten salt. Molten salt is inexpensive and allows for higher storage temperatures (290^{o}C). The main disadvantage is that it becomes solid below 220^{o}C and therefore must be maintained above this temperature. The receiver and storage tanks were replaced in order to use the new fluid. All pipes that carry the molten salt were heat-traced to avoid freezing the salt.

Solar Two (see Figure 3.3) began operation in November 1997 and operated fairly consistently for the next year. Preliminary measurements showed that the plant was operating near design expectations (8% efficiency). Parasitic power required to keep the molten salt from freezing was initially quite high. Changes in operating strategy and modifications in the design reduced parasitic power to acceptable levels.

In November 1998, the feeder pipe to the receiver collapsed because of an unforeseen transfer of loads. The system was repaired and the plant ran until April 1999 – the end of the demonstration phase. Solar Two has successfully demonstrated the concept of molten salt storage. The heliostats have held up well over the almost 20 years that the plant has been in existence.

In Europe, the German/Swiss PHOEBUS project is developing an air-based receiver for towers. A Spanish team (Colon Solar) uses a steam-based receiver. These systems are currently only in the 1-10 $MW_{thermal}$ range but may be able to be scaled up to larger sizes in the future. They are designed for gas turbine or combined cycle operation.

Figure 3.3 Solar Two Central Receiver



3.3.2 Central Receiver - Systems Assessed in this Study

The system design used at Solar Two served as a basis for this study, because it is the most mature. (Even then several years may be required before this system could be considered commercially ready.) Some of the other central receiver systems under development may offer lower costs in the future and as such this values given here can be viewed as conservative. Similar systems to the parabolic trough are examined for the central receiver so that direct comparisons can be made between the two technologies. Given that central receivers are a less mature technology, they may reach medium-term and long-term status at a later year than parabolic trough systems. Salt-storage is included with the central receiver systems to allow a high solar capacity and to eliminate the need for fossil-fuel back-up. For the near-term status, two systems are studied: 30 MW Rankine-cycle and a 30 MW solar boost in a ISCCS. In the longer term, larger systems and a hybrid solar/Rankine system are included in the analysis.

Table 3.6 Details of Central Receiver STPP

(multiple values are listed if value is different in near-term, medium-term and long-term scenarios)

	Rankine with Storage	ISCCS with Storage	Hybrid with Storage
Solar Field ('000 m^2)	275 / 826 / 1490	275 / 826 / -	- / 826 / -
Storage (hours)	6.5	6.5	6.5
Solar Capacity (MW)	30 / 100 / 200	30 / 100 / -	- / 100 / -
Total Capacity (MW)	30 / 100 / 200	130 /450 / -	130 / 450 / -
Solar Capacity Factor (%)	44.8 / 42.8 / 44.7 %	44.7 %	44.7 %
Total Capacity Factor (%)	50 %	50 %	50%

3.3.3 Central Receiver - System Costs & Performance

Cost and performance estimates have been made for the near-term status of two central receiver STPP. These estimates are summarized in Tables 3.7 and 3.8. It is important to note that because central receivers are at an earlier stage of development, the values quoted have a higher degree of uncertainty than the values for trough systems.

The solar-to-electricity efficiency for the Solar Two plant is 8.5%. This plant however, suffers from high parasitic power (because of its low capacity), low power cycle efficiency and poor heliostat optics. Studies show that if these problems were corrected, the plant could have an efficiency of 15% [DOE/EPRI, 1997]. Similar values are used in this report as indicative of what a totally new plant could achieve.

There is less information on the cost and performance of central receiver STPP than there is for parabolic trough systems. The construction costs from Solar One and Two are not relevant because there were pilot projects of only 10 MW capacity. Nevertheless, studies have been done on the potential costs of this technology. The construction cost of a 100 MW Rankine-cycle STPP in the U.S. was estimated at $3,270 and 19% lower at $2,660 in Brazil (if import taxes are removed) [Cordeiro,1997]. It is likely however, that the next central receiver project would be only 30 MW at a higher cost per kilowatt.

Table 3.7 Estimated Near-term Performance of Central Receiver STPP

Component	30 MW C.R. Rankine	30 MW C.R. ISCCS (130 MW Total)
	Case 6	**Case 7**
Heat Collection Efficiency	46.8%	46.8%
Power Cycle Efficiency	40.0%	40.0%
Parasitic Efficiency	84.0%	88.5%
Solar-to-Electric Net Efficiency	15.7%	16.5%
Annual Solar Efficiency	14.9%	15.7%
Plant Capacity	50%	50%
Solar Capacity	44%	47%

Table 3.8 Estimated Near-term Cost of Central Receiver STPP
(in $/kW total plant output)

Component	30 MW C.R. Rankine SEGS	30 MW C.R. ISCCS (130 MW Total)
Site Works	117	117
Heliostats & Tower	2267	2267
Thermal Storage	420	420
HTF System/Boiler	177	177
Power Block/ Balance of Plant	933	450
Services	391	343
Land	11	10
Contingency	646	566
Total (U.S. plant)	4950	4339
Discount in Developing Countries	-744	-650
Total	4209	3689
O & M Cost (¢/kWh)	2.6	1.6

3.4 CONVENTIONAL SYSTEMS

As discussed in Section 2.4, the STPPs are designed to displace conventional power plants that operate with capacity factors of between 25 and 50%. Besides capacity factor, the cost of conventional electricity will depend on the type of plant, cost of fuel and economic parameters used to levelize capital costs. In this report, the cost of conventional power is determined by estimating conventional plant capital and operating costs and applying the same economic parameters as used with the STPPs. This section outlines the typical capital and operating costs of conventional power plants. In Section 5.1, the cost of power (in cents/kWh) is computed and compared to values quoted in the literature to ensure the calculated costs are reasonable.

Four conventional power plants are examined in this study: a 400 MW coal-fired Rankine plant, a 300 MW gas or oil Rankine cycle, a 376 MW combined cycle natural gas plant and a 160 MW combustion turbine plant. The details of these plants are listed in Table 3.9. These plants are typical of size and type of plants built in developing countries. The first three plants are typically used to meet intermediate electricity loads (capacity factor = 50%), whereas the combustion turbine is typically used to meet peak loads (capacity factor <25%).

The cost and performance values were taken from the Annual Energy Outlook 1999 and Gas Turbine World 1997. Although these costs are likely based on a financial analysis as opposed to an economic analysis, the difference between these two costs is expected to be small and within the uncertainty in the analysis. The efficiency values are based on the lower heating value of the fuel and are consistent with values used in other studies [Kolb, 1998]. The capital cost value for the coal plant includes the use of scrubbers to meet World Bank requirements. The capital cost for the combined cycle plant is lower than was used in previous studies because of recent cost reductions for this technology. The Annual Energy Outlook also predicts a further 10 to 30% improvement in the cost performance of combined cycle plants over the next twenty years.

There is some indication that the cost of conventional plants is lower in developing countries than in the U.S. A contract was recently awarded to construct a 650 MW gas-fired Rankine cycle plant in Egypt. The cost of this system is $692/kW [IPP, 1998], significantly below the $1,004/kW given in Table 3.9. The lower cost is attributed to a combination of larger capacity than in Table 3.9 and the low labor costs in Egypt. Similarly, Lewis [1996] found a 15% capital cost saving for a refinery in India. For consistency in comparison to STPP (see Section 3.2.3), 15% lower capital and O & M costs are assumed for conventional plants and STPPs in developing countries.

Table 3.9 Estimated Current U.S. Cost and Performance of Conventional Power Plants

Component	160 MW Combustion Turbine	400 MW Rankine Scrubbed Coal	300 MW Rankine Gas/Oil	376 MW Combined Cycle Gas
	Case 0	Case 1A	Case 1B	Case 2
Annual Power Plant Efficiency	27.4%	34.4%	34.4%	53.5%
Capital Cost ($/kW)	$329/kW	$1016/kW	$1,004/kW	$366/kW
Annual O & M Cost (¢/kWh)	0.30 (25% C.F.)	0.86 to 1.38	0.75 to 1.25	0.40 to 0.75

The price for coal and natural gas is location dependent. In Egypt, the price for natural gas is $1/GJ [Geyer, 1996] whereas in Morocco the price is over $3/GJ [Pilkington, 1998]. In this study a median value of $2.37/GJ ($2.50 per MMBTU) is used, equal to the World Bank value for Europe [1998]. Sensitivity studies to energy price are performed. The price for coal using the same reference is $33 per metric ton ($1.14/GJ). All fuel costs are based on the higher heating value.

3.5 SUMMARY

Parabolic trough SEGS plants in southern California, with a total output of 354 MW, have operated reliably over the past 15 years. The maintenance costs for these plants, although high, have fallen with time. New, larger plants are expected to have O & M costs approximately twice that of conventional Rankine cycle plants. New parabolic trough STPPs are estimated to have a capital cost (in developing countries) that is $2,000 to $3,000 per kilowatt of solar capacity or 2.5 to 3.5 times that of conventional Rankine-cycle plants.

Central receiver STPPs are less mature than parabolic trough and will require several successful projects to scale up to reasonable sizes. The near-term costs of central receiver STPPs are close to $4,200 per kilowatt or five times that of conventional Rankine-cycle plants.

4. METHODOLOGY FOR CALCULATING LEVELIZED ENERGY COST

4.1 INTRODUCTION

This section builds on the data presented in Section 3 and develops levelized energy costs (LEC) for each of the solar and conventional systems discussed previously. Experience has illustrated that the calculation of levelized energy costs for renewable energy sources is both complex and often subject to debate. Moreover, calculated results can be significantly influenced by the methodology and the assumptions employed. Consequently, this section begins with an overview of the methodology and general economic assumptions employed in the calculation of LECs. This is followed by a discussion of the specific cost and performance inputs used.

4.2 LEC DEFINITION

Levelized energy cost (LEC) refers to a calculated stream of equal cash flows whose NPV is equal to that of a given stream of variable cash flows. If a project's levelized annual cash flow is divided by the annual amount of energy produced, the result is referred to as the levelized cost of energy. This result is widely used to compare competing energy sources and is normally calculated using constant dollars (i.e., in real terms that are net of inflation) [IEA, 1991]. The LEC is the sum of the annual fuel cost, annual operation and maintenance cost and the product of the capital cost times the fixed charge rate.

4.3 METHODOLOGY

4.3.1 Overview

The methodology employed in the calculation of the levelized electricity costs is based on the procedures outlined in the International Energy Agency (IEA) publication entitled, "*Guidelines for The Economic Analysis of Renewable Energy Technology Applications*" [1991]. The methodology outlined in the IEA publication has been developed explicitly to address the challenges posed in attempting to assess the economic feasibility of renewable energy technologies, which unlike conventional energy sources, do not have decades of experience.

With minor modifications, the methodology outlined in the IEA publication can be used in either public or private sector investment evaluations.

4.3.2 Public vs. Private Perspective

The choice of analytical perspective is critical. This is because important differences may occur between private and public sector analyses of renewable energy projects. These differences, in turn, may lead to different policy implications for the GEF and the World Bank.

The analysis employed in this study is a public sector, economic analysis; this means that the perspective is that of society as a whole. This is in contrast to a private, financial analysis where the perspective is that of a private investor. This is an important distinction. The basis for conducting private sector analysis includes market prices, taxes, depreciation, private cost of capital and applicable incentives etc. In other words the private, financial analysis attempts to determine the actual costs and revenues that will be realized by the investor [IEA, 1987]. Table 4.1 illustrates a number of the areas in which public sector economic analysis differs from the private financial analysis.

Table 4.1 Differences Between Private (financial)and Public Sector (economic) Analysis

Comparison Item	Private	Public
Viewpoint	Investor	Overall Society
Energy Prices (Benefits)	Prevailing	Social values reflect willingness to pay; alternative uses
Costs	Private, prevailing	Social values reflect opportunities foregone
External Effects	Ignored	Analyzed as much as possible.
Taxes	Considered	Ignored
Social Infrastructure (e.g., roads)	Ignored	Considered
Discount Rate	Reflects cost of borrowing, desired returns (often >10 to 15%)	Reflects social preferences and other factors (often 8 to 10%)
Decision Criteria	Payback or IRR above a given rate	Positive NPV at the Social Discount Rate
Time Frame	Short term	Life Cycle

Source: McDaniel's Research, Public Sector Perspectives on Renewable Energy Economics, Vancouver, BC

One important reason for employing a public sector economic approach to the assessment of solar energy options is that price does not always reflect all of the considerations relevant to decision makers. Within the context of this study, one particularly important example is the treatment of external effects, such as greenhouse gas emissions created by each of the electricity generating options. In a private sector analysis, these emissions are ignored; however, consideration of greenhouse gas emissions is an important driver in the current study.

Similarly, it is important to recognize that the conventional technologies and fuels (that provide the "parity target" for the solar technologies) have themselves been affected by subsidies or incentives over many years. In many countries, activities such as petroleum exploration, drilling and pipeline development have received substantial public development support that necessarily influences their current price. Similarly, the conventional power generation systems included in this study are mature technologies. The STPP technologies, on the other hand, are in the early development stage and consequently, the prices prevailing today are not necessarily indicative of the prices that may prevail in the future, under conditions of enhanced market share. (This is addressed in Section 5).

4.3.3 Economic Assumptions Employed in this Analysis

Previous experience with the calculation of LECs has shown that even modest changes to input assumptions (e.g., discount rate, fuel escalation rates etc.) can very significantly affect the resulting LEC. The major economic assumptions that are employed in this analysis are described below and summarized in Table 4.2, together with suggested ranges for sensitivity analysis. The technology specific cost and performance inputs are presented in the Sections 3 (current) and 6 (future).

Climate change as a result of greenhouse gas emissions is a societal problem. The impact on LEC of a credit for reduced emissions is studied in this report. The World Bank has found that a price of $10 to $40 per ton of carbon (or $2.75 to $11 per ton of CO_2) is likely to reflect the price range of carbon in a future carbon market [pers. com. Charles Feinstein, World Bank].

A 25-year assumed plant life is typically used in the power plant industry. Because of the relatively high discount rate, assuming a longer plant life has little impact on the LEC. The SEGS plants in southern California have been operating for up to 15 years with little indication that they would not last 25 years.

Most studies of STPP have used a discount rate of 8% and this value is used in this report. The World Bank however, typically uses a 10 to 12% discount rate in assessing projects in developing countries. Although this rate is high by developed world standards, it reflects the high opportunity cost for other investments in these countries. The sensitivity of the LEC to higher discount rates is studied.

The World Bank has projected the future cost of energy to the year 2020. Their estimates show a relatively flat price or slight decrease (in real terms) for coal, gas and oil. A 0% escalation rate is assumed for this study.

Table 4.2 Inputs - Economic Analysis

Item	Assumption
Inflation	The analysis uses constant (real) dollars and thus removes the effects of nominal inflation.
Base year	1998 has been selected as the base year. This is also assumed to be the "in-service" year. This base year is the year to which all cash flows have been discounted.
Project life	This is the useful life of the major technology components. A 25-year life is assumed, together with a sensitivity range of 20 to 30 years.
Real Price Changes	These are calculated from the base year values and are net of inflation.
Discount Rate	This reflects the time value of money; the discount rate enables cash flows that are generated over a period of time to be equated to amounts at a common point in time. In this case, the base year of 1998 is the chosen "point in time". For most economic analyses, real discount rates of 5 to 10% are commonly used. In this analysis, a rate of 10% is used and sensitivity analysis is conducted for rates of 8% and 12%.
Income/profit taxes/tariffs	The analysis is done before income tax and after deducting tariffs. The boundary of analysis is assumed to be at the level of a national government. This means that taxes and tariffs are a cost imposed on itself and retained by itself. i.e. there is no cost to the national government - it is only a redistribution.
Financing costs; cost of capital	Entire investment is treated as an initial cash outlay for the purposes of this economic analysis. Utility perspective does often include financing cash flows (debt & equity financing) but this is not the perspective of this study.
Replacement Expenses	Periodic replacements are included in the annual O & M costs.
Fuel Prices	Coal prices are assumed to be $33/tonne (World Bank, 1998) Natural gas rates are assumed to be $2.37/GJ (World Bank, 1998) The base case rate of fossil fuel price escalation is assumed to be 0%, based on World Bank projections to the year 2020. Sensitivity analysis is conducted at +/- 25% increase over plant life (1% annual change).
External Effects	Carbon dioxide emissions are considered. A credit of $7/tonne of avoided carbon dioxide emissions (relative to base case) is employed. Sensitivity analysis is also provided at carbon dioxide values of $2.75 and $11 per avoided tonne.

4.4 CALCULATION OF SOLAR LEC

One of the difficulties in comparing the LEC of STPP options is that the solar contribution is not equivalent. Plants with a low solar contribution (e.g., ISCCS) will have a total plant LEC close to that of conventional (combined cycle) plants almost regardless of its cost giving the impression of being very close to cost-effective status. Furthermore, comparing the LEC values for the whole plant does not indicate how much the solar cost/performance must improve for the system to be cost effective. To avoid this problem, this report compares LECs of the solar only component. Two different approaches are used to determine the solar LEC depending on the design of the STPP.

Rankine-cycle STPPs are designed as a direct replacement for a conventional power plant and the solar portion can operate as a stand-alone plant. These plants are operated on solar energy during sunny periods and on fossil-fuel during cloudy or non-daylight periods. It is difficult to allocate system costs (initial and annual operation and maintenance) to the solar system and the fossil-fuel system since they share many components (e.g., steam turbine).

This report follows a methodology similar to that proposed by Kolb [1998] to determine the solar LEC. The first step is to identify the "baseline", that is, the power plant that will be built if the solar option is not pursued. This plant may or may not be the same type or size as the solar plant. The initial cost, annual costs and LEC, is then estimated for this plant. The type of plant and its capacity factor are discussed in Section 4.4.

The second step is to determine the LEC for the complete STPP and the non-solar competition. The final step is to back out the LEC for the solar portion of the STPP using the formula given below. The assumption is that the value of the power produced by the STPP when operating on fossil fuel is equal to that of the non-solar competitor. With this methodology some of the STPP capital cost gets allocated to the conventional power cost.

$$LEC_{SOLAR} = \frac{\left[LEC_{STPP} - (1 - FS) \cdot LEC_{CON}\right]}{FS}$$

Where LEC_{SOLAR} is the LEC of the solar only component

LEC_{STPP} Is the LEC of the STPP (solar and back-up components)

LEC_{CON} Is the LEC of the conventional plant that would have been built in place of the STPP

FS is the fraction of the STPP annual capacity factor powered by solar energy

A different methodology is used for those plants where solar is an add-on to a conventional plant (e.g., ISCCS and Hybrid/solar plants). In these plants, it is much easier to identify the solar capital and operating costs since the plant can operate efficiently without the solar systems. For these STPPs, the incremental cost of the solar components is used to determine the solar LEC.

The final step in the methodology is to compare the solar LEC to that of the conventional power plant it is replacing. If a utility is considering an ISCCS plant, the baseline is a slightly larger (or another) combined-cycle plant (without the solar boost) that provides the same output as the integrated solar/combined cycle plant. As will be shown later in Section 5.1, combined cycle plants have the lowest LEC. Nevertheless, utilities are still constructing Rankine-cycle plants. For example, Egypt recently awarded a contract to construct a 650 MW gas-fired Rankine-cycle plant [IPP, 1998]. There are several potential reasons for this:

- Natural gas is not available for a combined-cycle plant,
- A mixture of generating technologies is desired to avoid being too dependent on one technology,
- Local designers and/or plant operators are more familiar with Rankine-cycle plants, and
- Rankine-cycle equipment may be available locally.

If a utility decides on a Rankine cycle power plant then the competing solar alternative is a Rankine-cycle STPP. Thus in this report, ISCCS will be compared against a Combined Cycle gas plant and Rankine-cycle STPPs will be compared to a conventional Rankine-cycle power plant with either coal or natural gas as the fuel.

5. CURRENT LEVELIZED ENERGY COSTS

5.1 CONVENTIONAL POWER PLANTS

The current LEC was determined for coal and gas-fired power plants. The results are summarized in Table 5.1 and are based on 50% and 25% capacity factors and a discount rate of 10%. For 50% capacity factor plants, the electricity generation costs range from 3.0 cents/kWh (for combined-cycle gas plants) to 5.6 cents/kWh (for gas-fired Rankine cycle plants). Anderson [1988] has evaluated the LEC for different power plant capacity factors. He quotes a value of 6.3 cents/kWh for 50% capacity factor gas-fired power plants: an LEC close to the value in Table 5.1. Although gas-fired Rankine-cycle plants have a higher LEC than coal-fired plants, they benefit from lower carbon dioxide emissions. If the cost of carbon emissions are included, these two plants have almost the same cost of power. In this study, the cost of intermediate load power is taken as 4.3 cents/kWh with emissions based on a coal-fired plant.

Table 3.1 gives a cost for a 25% capacity factor plant as 5.6 cents/kWh. Peaking power in Jordan has a cost of production of 6.3 cents/kWh [Geyer, 1997]. Anderson [1998] quotes a price of 8.3 cents/kWh for a 25% capacity factor plant. These values bracket the costs calculated for 25% capacity factor plants. A mid-range energy cost of 6.9 cents/kWh is used in this study for 25% capacity factor power.

The calculated costs for 25 and 50% capacity factor power are used as a high and low scenario with which to compare STPP power production costs. These conventional costs are not however, the highest and lowest costs of energy. Power plants meeting the base load or using low cost fuel will have a lower electricity production cost. Power plants operated to meet a spiky peak or using high cost fuel will have a higher electricity production cost.

Table 5.1 Current LEC for Intermediate and Peak Conventional Power Plants
(in cents/kWh)

LEC (¢/kWh)	160 MW Combustion Turbine	400 MW Rankine – Coal	300 MW Rankine - Gas	376 MW Combined Cycle
	Case 0	Case 1A	Case 1B	Case 2
Capacity Factor	25%	50%	50%	50%
Capital Cost	1.8	2.4	2.2	0.9
Fuel Cost	3.5	1.2	2.7	1.8
O & M Cost	0.3	0.7	0.6	0.3
Total	**5.6**	**4.3**	**5.6**	**3.0**

5.2 STPP

The LEC was determined for five STPPs: three trough plants and two central receiver plants. The details of these plants are summarized below. All plants are compared on the basis of the same capacity factor, although their solar share varies considerably. The details of the analysis are contained in Appendices A and B.

Tables 5.1 and 5.2 provide a summary of the current LECs for each of the options studied. If the LEC for the STPP is less than that of the conventional plant, the STPP is deemed to be cost-effective. LEC values are given for the total STPP (a mixture of solar and fossil-fuel generated electricity) and the solar only portion. In calculating the solar only portion of the plant LEC, the fossil-fuel generated electricity is assumed to have a value equal to the LEC for the power plant it is replacing. Since coal-fired Rankine-cycle plants have a lower cost than gas-fired Rankine plants, the coal plant is used as the reference case.

The ISCCS plants produce power at a 70% premium over combined cycle gas plants. The solar portion of the plant has a LEC that is over 12 cents/kWh: three to four times that of a combined cycle plant. The solar LEC for the Tower is less than for the Trough because of the use of thermal storage. The solar capacity factor for the Tower is almost twice that of the Trough meaning that the solar boost runs for almost twice as many hours. A credit of $25 per tonne of carbon displaced reduces the solar LEC by only a small amount – 0.7 cents/kWh.

The solar LECs for the Rankine-cycle STPPs are 10 to 20% higher than for the same size ISCCS. However, as the size of plant is increased to 200 MW the solar LEC drops to 10 cents per kWh and with a CO_2 emissions credit to 8.3 cents/kWh. This last value is about twice the cost of power from a coal-fired Rankine-cycle plant.

Table 5.2 Current LECs for Combined Cycle Plants (in cents/kWh)

	Combined-Cycle Gas	30 MW ISCCS-Trough	30 MW ISCCS-Tower with storage
	Case 2	**Case 5**	**Case 7**
Total Plant LEC	3.0 - 4.1	4.42	-
Solar LEC	-	15.3	12.1
- with CO_2 Credit	-	14.6	11.4

Table 5.3 Current LECs for Rankine-Cycle Plants (in cents/kWh)

	Coal-fired Rankine Plant	30 MW Rankine-Trough	200 MW Rankine-Trough	30 MW Rankine-Tower with storage
	Case 1A	**Case 3**	**Case 4**	**Case 6**
Total Plant LEC	4.3 - 6.9	10.4	7.2	13.9
Solar LEC	-	16.6	10.1	15.3
- with CO_2 Credit	-	14.9	8.3	13.4

5.3 SENSITIVITY ANALYSIS

Previous LEC modeling experience has shown that, in addition to discount rate, LEC values are sensitive to assumptions about fuel price, project life and credits. Tables 5.4 and 5.5 provide a summary of the resulting LECs under each sensitivity scenario. Of all the factors considered, discount rate has the largest impact on solar LEC. Decreasing the discount rate from 10 to 8% causes the solar LEC to fall almost 15% from 15.3 to 13.4 cents/kWh for the 30 MW ISCCS-Trough and from 10.1 to 8.9 cents/kWh for the 200 MW Rankine-Trough. On the other hand, the cost of conventional power falls by only 7%.

The values currently being considered for carbon credit have a significant impact on solar LEC. The maximum likely credit being considered ($40/tonne carbon) reduces solar LEC by 1 cent/kWh when displacing natural gas and 2 cents/kWh when displacing coal. A 25% increase in fuel costs has no impact on solar LEC but increases the conventional power plant LEC by 0.3 to 0.4 cents/kWh. Increasing plant life to 30 years decreases the solar LEC by only 4%.

Table 5.4 Sensitivity of LEC to Assumptions – Combined Cycle Plants (in cents/kWh)

	Baseline Energy Cost[2]	30 MW ISCCS-Trough	30 MW ISCCS-Tower with storage
	Case 2	**Case 5**	**Case7**
Base case[1]	3.0 – 4.1	15.3	12.1
- 8% discount	2.8 – 3.9	13.4	10.6
- 12% discount	3.1 – 4.2	17.3	13.7
- $10/tonne carbon credit	3.0 – 4.1	15.0	11.9
- $25/tonne carbon credit	3.0 – 4.1	14.6	11.4
- $40/tonne carbon credit	3.0 – 4.1	14.2	11.0
- 25% higher fuel cost	3.4 – 4.5	15.3	12.1
- 25% lower fuel cost	2.5 – 3.6	15.3	12.1
- 20 year plant life	3.0 – 4.1	16.2	12.8
- 30 year plant life	2.9 – 4.0	14.8	11.8

[1] – 10% discount, 25 year life, no carbon credit

[2] – based on a combined cycle gas plant operating at 50 and 25% capacity factors

Table 5.5 Sensitivity of LEC to Assumptions – Rankine-Cycle Plants (in cents/kWh)

Cents/kWh	Baseline Energy Cost[2]	30 MW Rankine-Trough	200 MW Rankine-Trough	30 MW Rankine- Tower with storage
	Case 1A	**Case 3**	**Case 4**	**Case 6**
Base case[1]	4.3 – 6.9	16.6	10.1	15.3
- 8% discount	4.0 – 6.6	14.6	8.9	13.5
- 12% discount	4.6 – 7.2	18.6	11.4	17.1
- $10/tonne carbon credit	4.3 – 6.9	15.9	9.4	14.5
- $25/tonne carbon credit	4.3 – 6.9	14.9	8.3	13.4
- $40/tonne carbon credit	4.3 – 6.9	13.9	7.2	12.3
- 25% higher fuel cost	4.6 – 7.2	16.5	10.1	15.2
- 25% lower fuel cost	4.0 – 6.6	16.6	10.1	15.3
- 20 year plant life	4.4 – 7.0	17.4	10.7	16.0
- 30 year plant life	4.2 – 6.8	16.1	9.8	14.8

[1] – 10% discount, 25 year life, no carbon credit

[2] – based on intermediate and peak load power plants (see Section 5.1)

5.4 CONCLUSIONS AND STUDY IMPLICATIONS

At the current state of technology development, the cost of solar-generated electricity is between 10 and 15 cents per kWh (at a 10% discount rate). This is 1.5 to four times more expensive than power from conventional power plants. Although solar power from ISCCS is 10% to 20% less expensive than for a similar sized Rankine-cycle STPP, it is competing against a much lower cost conventional power plant (combined-cycle).

6. FUTURE COST AND PERFORMANCE

6.1 INTRODUCTION

The preceding section illustrated that the current LECs for solar technologies are approximately 1.5 to four times greater than those for conventional intermediate and peak load power plants. However, this current cost gap may not continue in the longer term, particularly if there is support for commercialization of STPPs. This section, therefore, examines expected future costs for both conventional and solar alternatives.

The objective is to determine the scope of expected future price differences under varying levels of future technology market penetration. These results will, therefore, help to determine the scope of investment required and the possible parameters of public sector support required, if any, to close the gap. Subsequent stages of the analysis will then address whether or not this required level of investment is feasible or not.

The discussion of future prices for the solar alternatives is more difficult, as they are not currently fully commercialized technologies and prices have scope for future declines. Two approaches were employed in attempting to determine likely future STPP prices:

- Engineering estimates of likely future cost or performance improvements were developed based on known technical improvements and likely cost reductions through mass production and commercialization. This analysis was done on a sub component basis and aggregated.
- Expected STPP technology cost reductions were analyzed, using the concept of experience curves.

The remainder of this section presents the results of these two approaches.

6.2 FUTURE STPP COSTS - Engineering Approach

6.2.1 Parabolic Trough

The future cost and performance of the parabolic trough STPP was examined for two time-periods: medium-term and long-term (see Table 6.1). In the medium-term, the collector efficiency is expected to increase approximately two percentage points primarily because of an improved absorber coating (solar absorptivity of 96% and an emmissivity of 7% at 350^{o}C).

In the long-term, several significant changes in the technology are anticipated. These will result in significant efficiency improvements and lower costs. First, tilting of the collector array eight degrees from the horizontal increases the solar radiation available and the optical efficiency. This concept was being studied by Luz and was to be part of their fourth generation collector. Tilting of the collector towards the sun reduces reflective and shadowing losses particularly in the winter.

Second, better integration with the power plant and higher collector operating temperatures will improve the power plant cycle efficiency from 38% to 39% and 40% in the mid and long term.

Finally, it is anticipated that a cost-effective thermal storage system will be developed to store solar heat later into the peak electrical period. This system has been added as a long-term option. Thermal storage increases the solar capacity factor of the plant and reduces parasitic energy and start-up losses and improves part load efficiency.

The system efficiency could be improved even further by conversion to direct steam generation. The collector heat transfer fluid is replaced with the water/steam used in the turbine. This will require the collectors to be able to withstand medium-pressure steam and the fluid flow to be more evenly controlled. Whether these changes will result in a net improvement in system LEC is not yet clear, and they have not been included in this analysis.

Table 6.1 Estimated Future Performance of Parabolic Trough STPP

Component	1000 MW ISCCS (450 MW total) - Medium-term	200 MW Rankine SEGS - Medium-term	200 MW Rankine SEGS - Long-term	200 MW SEGS with Storage - Long-term
	Case 8	**Case 9**	**Case 10**	**Case 11**
Heat Collection Eff.	46.0%	46.0%	51.9%	53.6%
Power Cycle Eff.	39.0%	39.0%	40.0%	40.0%
Parasitic Efficiency	90.2%	83.6%	86.7%	90.2%
Solar-to-Elec Net Eff.	16.2%	15.5%	18.0%	18.4%
Annual Solar Eff.	14.6%	14.0%	16.2%	16.6%
Plant Capacity	50%	50%	50%	50%
Solar Capacity	26.2%	25.1%	26.4%	50%

The costs are expected to fall as more experience is gained with the technology. Four factors will contribute to the cost reductions: solar system optimization, economies of scale, standardized engineering, and competitive pressures. As collector production ramps up to supply new STPPs, manufacturing cost reductions will occur. A 15% cost reduction has been estimated by incorporating known improvements into the system [Cohen and Kearney, 1994]. Potential cost reductions include replacement of flexible hoses with ball joints, wider pylon spacing, and lower cost coatings. Previous costing studies [Pilkington, 1996] have shown that a doubling of system size results in a 12 to 14% reduction in capital cost on a per kW basis. Increasing plant size from 30 MW to 200 MW reduces the cost per kilowatt by approximately 30%. Better integration of the solar and conventional components and standardization of designs is expected to reduce costs by 5% [Pilkington, 1996]. In the long-term, the cost of the conventional Rankine-cycle components should be on a par with conventional Rankine-cycle power plants ($800/kW). As the industry matures and new players enter the market, competitive pressures may further drive down prices. Because of the difficulty in estimating this impact, only a modest decrease has been assumed in this study.

Table 6.2 shows the combined effect of future cost reductions and performance improvements. The result is a 50% reduction in the cost-per-kilowatt for parabolic trough systems (from a 30 MW current system to a 200 MW long-term system).

Table 6.2 Estimated Future Cost of Parabolic Trough STPP

(in $/kW nominal solar output)

Component	100 MW ISCCS (450 MW Total) - Medium-term	200 MW Rankine - Medium-term	200 MW Rankine - Long-term	200 MW Rankine with Storage - Long-term
Site Works	70	53	50	55
Solar Field	1011	932	792	1026
Thermal Storage	0	0	0	476
HTF System/Boiler	225	214	196	67
Power Block	163	265	252	206
Balance of Plant	190	154	146	120
Services	166	162	144	195
Land	10	10	9	16
Contingency	274	267	237	322
Total	2109	2055	1825	2481
Discount in Dev. Countries	-316	-308	-273	-372
Total	1793	1747	1551	2109
O & M Costs (c/kWh)	0.59	0.94	0.75	0.48

6.2.2 Central Receiver

The cost and performance of central receiver systems are expected to improve significantly in the mid- and long-term. Because this technology is less mature than the parabolic trough, more dramatic improvements are expected. Table 6.3 lists the expected system performance values based on values provided by SunLab. The first improvement in the performance of the central receiver system will be the addition of a selective surface on the receiver. The reduction of surface emmissivity from 85% to 20% is expected to reduce heat losses by 60% and improve overall collection efficiency from 46% to 49%. In the long-term, collector efficiency will increase to 52% through a 2% increase in receiver absorbtivity (94 to 96%), and higher mirror reflectivity because of improved coatings and better mirror washing.

As the plants are made larger, the power cycle efficiency will improve slightly from 40 to 43%. The combination of larger plants, better operating procedures and higher solar capacity factor will reduce parasitic losses to keep the salt a liquid.

Table 6.3 Estimated Future Performance of Central Receiver STPP
(all systems have thermal storage)

Component	100 MW ISCCS (450 MW Total) - Medium-term	100 MW Rankine - Medium-term	100 MW Hybrid Coal Rankine - Medium-term	200 MW Rankine - Long-term
	Case 12	**Case 13**	**Case 14**	**Case 15**
Heat Collection Eff.	49.3%	49.3%	49.3%	52.1%
Power Cycle Eff.	43%	43%	43%	43%
Parasitic Efficiency	87.0%	82.9%	87.0%	90.6%
Solar-to-Elec. Net Eff.	18.5%	17.6%	18.5%	20.3%
Annual Solar Eff.	17.6%	16.7%	17.6%	19.3%
Plant Capacity	50%	50%	50%	50%
Solar Capacity	47%	45%	47%	50%

The costs of central receiver STPP are expected to drop significantly as this technology is commercialized. The largest cost reductions are expected with the heliostats. Heliostats represent approximately 50% of the total solar plant cost. Prices for heliostats have been obtained from U.S. manufacturers based on production volumes (see Figure 6.1) [DOE, 1997]. Installation costs are only a few percent of the heliostat cost, so that these values can be assumed to be representative of installed costs. For small production runs (in the order of a few hundred), a price of $180/m^2 is expected. (This value was used for the current scenario, see Section 3.3.2.) A 100 MW plant (the medium-term) scenario would require 6000 heliostats and the price is expected to drop to $126/m^2 is anticipated. In the long-term at high production rates, the price is expected to fall to $70/m^2.

Central receiver systems will benefit from the same cost reduction factors as described for the parabolic trough. There is however greater uncertainty in the central receiver values because they are at an earlier stage in their development. The effect of the cost reductions and performance improvements are seen in Table 6.4. Because of the large reduction in heliostat costs, central receiver systems show a 63% reduction in cost-per-kilowatt (current 30 MW to a long-term 200 MW). In the long-term, Central Receiver systems are predicted to have a 25% lower cost than parabolic trough systems. The prime reason for the lower cost is the reduction of piping. Parabolic trough systems must use insulated piping to connect all the collector arrays. Central receivers concentrate and collect the heat by reflecting the solar radiation to a central source.

Figure 6.1 Heliostat Price as a Function of Annual Production Volume
(source DOE/EPRI, 1997)

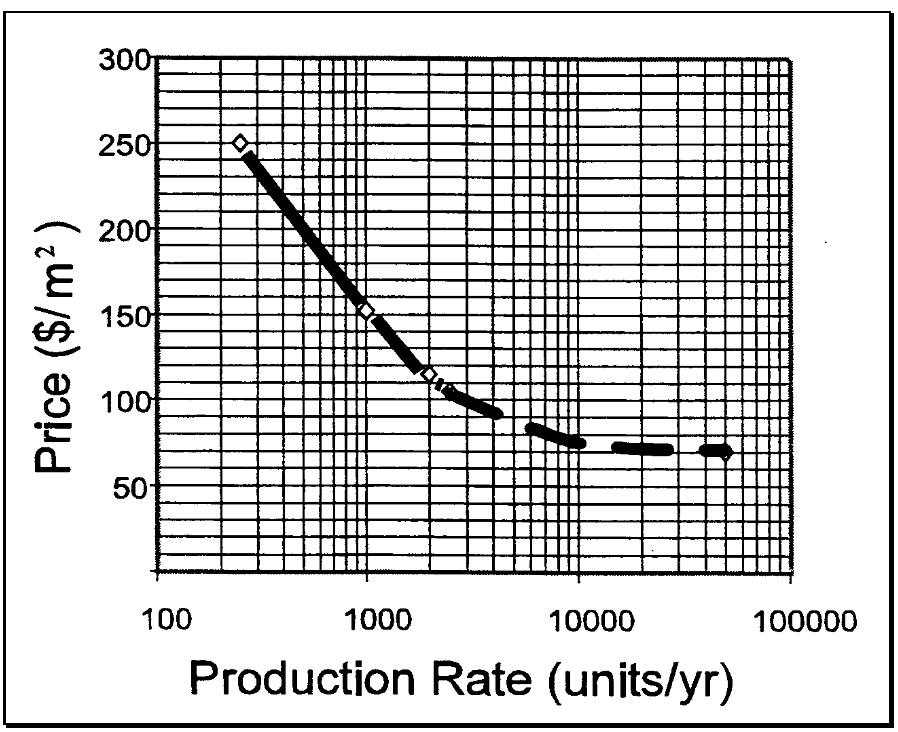


Table 6.4 Estimated Future Cost of Central Receiver STPP (in $/kW nominal solar output)

Component	**100 MW ISCCS (450 MW Total) - Medium-term**	**100 MW Rankine - Medium-term**	**100 MW Hybrid Coal Rankine - Medium-term**	**200 MW Rankine - Long-term**
	Case 12	**Case 13**	**Case 14**	**Case 15**
Site Works	49	49	49	39
Heliostats and Tower	1290	1290	1290	712
Thermal Storage	240	240	240	190
HTF System/Boiler	110	110	110	85
Power Block/Balance of Plant	280	570	280	415
Services	198	227	198	145
Land	11	11	11	11
Contingency	327	375	327	239
Total	2505	2872	2505	1836
Discount in Dev. Countries	-375	-431	-375	-275
Total	2130	2441	2130	1561
O & M Costs (c/kWh)	0.60	1.20	0.60	0.60

6.3 FUTURE STPP COSTS - Experience Curve Approach

Experience curves are a concept that has been developed and applied to a variety of new technologies. They cannot be considered an established theory or method but rather a correlation phenomenon that describes how unit costs decline with cumulative production. Experience curves, therefore provide an improved understanding of long-term patterns of cost development.

A specific characteristic of the experience curve is that cost declines by a constant percentage with each doubling of the total number of units produced. Generally, the curve is defined as:

$C_{cum} = C_o \times CUM^b$

where:

C_{cum} is the cost per unit as a function of output.

C_o is the cost of the first unit produced

CUM is the cumulative production over time and

b is the experience index.

The experience index is used to calculate the relative cost reduction ($1 - 2^b$) for each doubling of the cumulative production. The value (2^b) is called the progress ratio (PR) and is used to express the progress of cost reductions. A PR of 80%, for example, means that costs are reduced by 20% each time that the cumulative production is doubled. [Neij, 1997]

The cost reduction of the experience curve refers to total costs (labor, capital, R&D, etc). The experience process is a long-term development process which represents the combined effect of a number of parameters. The sources of cost reductions are:

- production changes (process innovations, learning effects and scaling effects)
- product changes (innovations, design standards, redesign)
- changes in input prices.

Cost reductions depend on the diffusion and adoption of new technologies, and vice versa; costs fall when production is expanded and market demand is expanded when costs fall.

STPP technologies are modular and therefore provide greater opportunity for factory-based automatic production. They are, therefore, susceptible to cost reductions. It should be noted that a technology break through would result in a discontinuity in the experience curve. This could mean faster cost reductions from current conditions than indicated by the experience curve.

Table 6.5 shows Progress Ratios for a range of relevant technology types. Given that STPP technology is of a modular nature, a PR range of 0.70 to 0.95 may be expected.

Table 6.5. Progress Ratios for Selected Technologies (source: Neij, 1997)

	Average in the literature	Range in the literature
Plants:	0.90	0.82 to 1.0
Large scale	> 1.0	
Wind	0.96	
Small scale	0.87	
Fuel Cells[1]	0.84	
Module Technologies	0.80	0.70 to 0.95
Photovoltaics	0.80	
Continuous Processes	0.78	0.64 to 0.90

[1] – Hosier, R. and Larson, E., 1999. GEF Participation in Fuel Cell Commercialization

Parabolic Troughs

By plotting the existing data for installed capital costs (adjusted to 1998$) for SEGS I to IX as shown in Figure 6.2, we see that a PR of 0.88 approximates the cost reduction trends for the trough technologies. As noted by Neij, a reliable estimate of the PR for any technology can only be made after many doublings of experience. Since at most there has only been 3 doublings in capacity, it is advisable to judge future cost reductions using a range of progress ratios. For parabolic troughs, a lower PR of 0.85 and an upper PR of 0.92 provide reasonable experience curve guidelines (see Figure 6.2). The area in between these two curves gives an indication of the cost range of future STPP technologies. The cost performance estimates developed in Section 6.2 for mid- and long-term trough technologies generally fall in the range projected by the upper and lower experience curves.

Central Receivers

Determination of the progress ratio for central receiver technologies is difficult due to the limited commercialization of this STPP. However, given the many similarities between troughs and central receivers, it is safe to assume that they will follow the same experience curves. Figure 6.3 is based on the near-term estimate for central receivers as the starting point, along with experience curves of 0.85, 0.88 and 0.92 emanating from this point. The projections for mid- and long-term cost performance estimates from Section 6.2 are also plotted. Again, the projected future costs fall well within the range established by the experience curves. Based on this analysis, it is assumed that the future cost performance projections are reasonable and are used in the calculation of future solar LEC.

Figure 6.2 Parabolic Trough Experience Curve

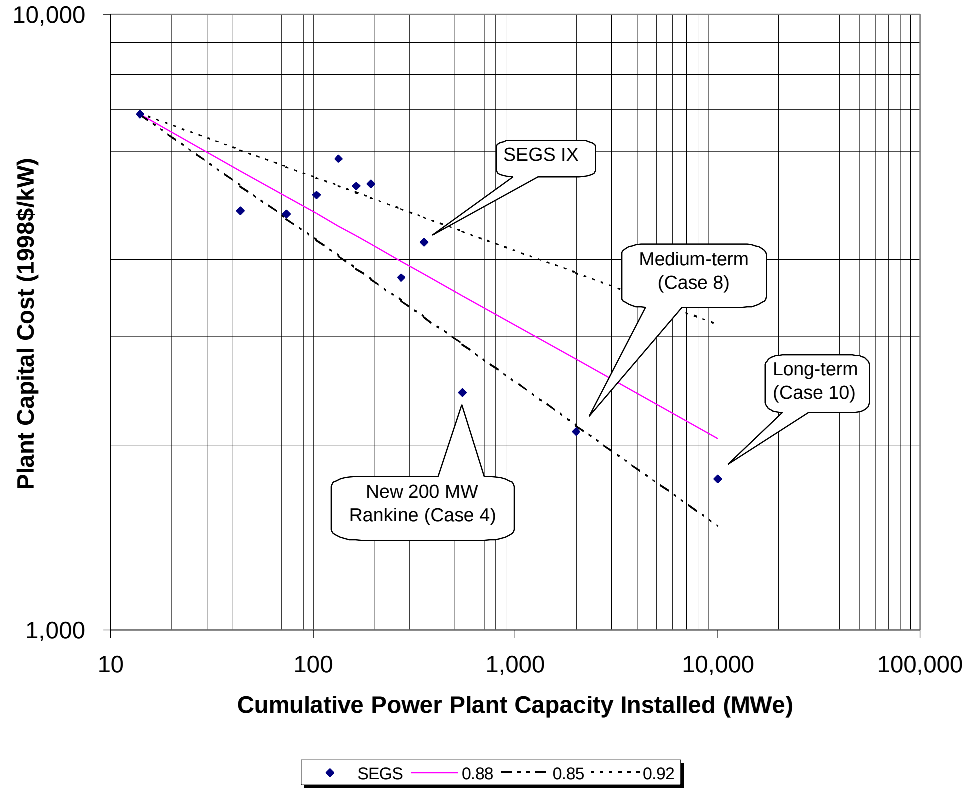
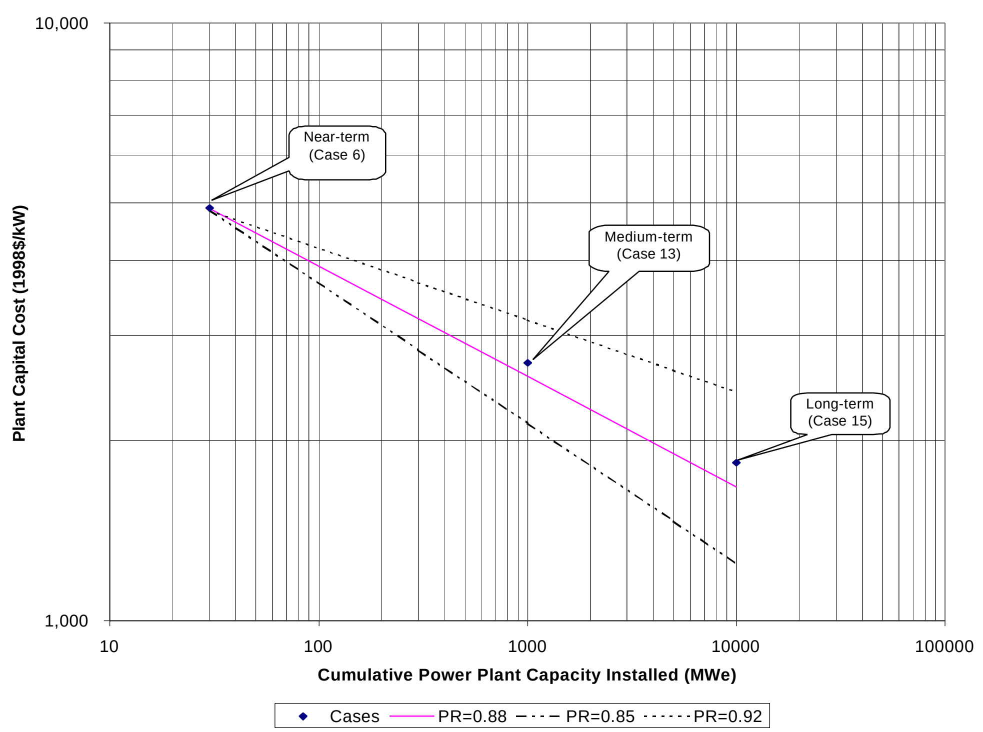


Figure 6.3 Central Receiver Experience Curve



6.4 BASELINE TECHNOLOGIES

The baseline electricity generation options are mature technologies. No significant capital cost decline is expected for Rankine-cycle systems over the next 20 years [DOE, 1998]. In fact, coal plants might become more expensive, as requirements for further improvements to plant environmental performance are demanded. The experience curves of large electricity generating facilities such as coal-fired plants have shown cost increases over time PR>100% - primarily due to the addition of environment and safety features to plants [Neij, 1997].

Modest performance improvements and cost reductions are predicted for combined cycle plants [DOE, 1998]. These changes might result in a slight decrease in combined cycle electricity costs.

Average future costs of conventional grid-connected electricity are expected to be in the range of 2.4¢ to 5¢/ kWh. The upper price range of 5¢ is expected to be for large scale coal plants while the lower range is expected to be for new combined cycle power plants with natural gas prices of $US 2.2/GJ [Energy Policy – Vol. 23, 1997 – pg. 1103]. These prices are consistent with the 50% capacity factor energy prices quoted in Section 5.1. Peak electrical power will of course have a higher cost.

These baseline future cost levels represent the longer-term targets that the STPP systems must meet if they are to achieve widespread market penetration.

6.5 CONCLUSIONS

Two approaches were used to predict the future cost performance of STPP: an engineering approach based on known technical improvements and cost reductions from commercialization and the experience curve approach. The two approaches yielded similar results. The cost-per-kilowatt of trough plants are expected to fall by 40% and central receiver systems are expected to fall by over 60%. The cost of electricity from conventional power plants is expected to stay constant over the next twenty years.

7. FUTURE LEVELIZED ENERGY COSTS

7.1 RESULTS FOR STPP

The LEC was determined for the medium-term and long-term scenarios. Two 100 MW ISCCS plants were examined: one trough and one tower. Six Rankine-cycle systems were examined: three in the medium-term and three in the long-term. The details of the analysis are contained in Appendices A and B.

Tables 7.1 is summary of the results for the ISCCS. The combination of a larger system (100 MW instead of 30 MW) and future cost performance improvements reduces the solar LEC from an average of 12 cents/kWh to 9 cents/kWh. While this represents a significant improvement in cost effectiveness, the ISCCS are still three times more expensive than conventional combined cycle plants. It is unlikely that either uncertainty in the economic inputs or future cost reductions will be able to bridge this gap.

Table 7.1 Medium-term LECs for Combined Cycle Plants (in cents/kWh)

	Combined-Cycle Gas	100 MW ISCCS-Trough (medium-term)	100 MW ISCCS-Tower with storage (medium-term)
		Case 8	Case 12
Total Plant LEC	3.0 – 4.1	-	-
Solar LEC	-	10.0	7.1
- with CO_2 Credit	-	9.3	6.4

Tables 7.2 and 7.3 provide a summary of the medium-term and long-term LECs for each of the Rankine plant options studied. Over this period, the cost of solar generated power is expected to fall from the 10 to 15 cent/kWh range to the 5 to 6 cent/kWh range. At this point, STPP are cost competitive with peaking coal-fired or gas-fired Rankine plants. The addition of thermal storage (if developed) for trough systems does not significantly improve the solar LEC; it does however, increase the solar capacity factor and so opens the possibility to supply into the higher cost peak electricity market. In the long term central receiver systems are expected to produce power at approximately 25% lower cost than a similar size trough system.

Table 7.2 Medium-term LECs for Rankine-Cycle Plants (in cents/kWh)

	Coal-fired Rankine Plant	200 MW Rankine-Trough	100 MW Rankine-Tower with storage	100 MW Hybrid/Rankine-Tower with storage
		Case 9	**Case 13**	**Case 14**
Total Plant LEC	4.3 – 6.9	6.1	7.9	7.0
Solar LEC	-	8.0	8.6	9.6
- with CO_2 Credit	-	6.2	6.7	7.8

Table 7.3 Long-term LECs for Rankine-Cycle Plants (in cents/kWh)

	Coal-fired Rankine Plant	200 MW Rankine-Trough	200 MW Rankine – Trough with storage	200 MW Rankine- Tower with storage
		Case 10	**Case 11**	**Case 15**
Total Plant LEC	4.3 – 6.9	5.2	6.1	4.9
Solar LEC	-	6.0	6.1	5.0
- with CO_2 Credit	-	4.2	4.3	3.2

7.2 SENSITIVITY ANALYSIS

A sensitivity study was conducted on the long-term value of solar LEC to model inputs. Regardless of model inputs, the LEC for all solar options fell within the range for conventional power. With carbon dioxide credits considered, all STPPs have LECs below that of the lowest cost coal-fired Rankine plant.

Table 7.4 Sensitivity of Long-term LEC to Assumptions – Rankine-Cycle Plants
(in cents/kWh)

Cents/kWh	Coal-fired Rankine Plant[2]	200 MW Rankine-Trough	200 MW Rankine-Trough with storage	200 MW Rankine- Tower with storage
		Case 10	**Case 11**	**Case 15**
Base case[1]	4.3 – 6.9	6.0	6.1	5.0
- 8% discount	4.0 – 6.6	5.3	5.4	4.4
- 12% discount	4.6 – 7.2	6.9	7.0	5.6
- $10/tonne carbon credit	4.3 – 6.9	5.3	5.4	4.3
- $25/tonne carbon credit	4.3 – 6.9	4.2	4.3	3.2
- $40/tonne carbon credit	4.3 – 6.9	3.1	3.2	2.1
- 25% fuel cost increase	4.6 – 7.2	6.0	6.1	5.0
- 25% fuel cost decrease	4.0 – 6.6	6.0	6.1	5.0
- 20 year plant life	4.4 – 7.0	6.4	6.5	5.3
- 30 year plant life	4.2 – 6.8	5.9	5.9	4.8

[1] – 10% discount, 25 year life, no carbon credit, [2] – range is for 50 and 25% capacity factors

7.3 CONCLUSIONS

The solar LEC is expected to fall to less than half current values as a result of performance improvements and cost reductions. Even with these improvements, the solar portion of ISCCS plants will produce power that is still more expensive than a combined-cycle plant firing on gas at current price levels. ISCCS plants may be an effective short-term strategy to get STPP re-started but they require cost reductions beyond those currently foreseen to be cost competitive with natural gas combined-cycle plants.

The potential for STPP to compete with Rankine cycle plants (either coal, gas or oil) is promising. In the long-term, LEC for Trough Rankine plants are expected to be within the cost range for conventional peaking plants. STPPs with a credit for CO_2 reduction have a lower LEC than coal-fired Rankine plants.

8. CONCLUSIONS TO PART A

New parabolic trough STPPs are estimated to have a capital cost (in developing countries) that is $2,000 to $3,000 per kilowatt, or 2.5 to 3.5 times that of conventional Rankine-cycle plants. Central receiver STPPs are less mature than parabolic trough and will require several successful projects to scale up to reasonable sizes. The near-term costs of central receiver STPPs are close to $4,200 per kilowatt or five times that of conventional Rankine-cycle plants.

At the current state of technology development, the cost of solar-generated electricity is between 10 and 15 cents per kWh (at a 10% discount rate). This is 1.5 to 4 times more expensive than power from conventional power plants. Although solar power from ISCCS is 10% to 20% less expensive than for a similar sized Rankine-cycle STPP, it is competing against a much lower cost conventional power plant (combined-cycle).

The cost-per-kilowatt of trough plants are expected to fall by 40% and central receiver systems are expected to fall by over 60%. The cost of electricity from conventional power plants is expected to stay constant over the next twenty years.

The solar Levelized Energy Cost (LEC) is expected to fall to less than half current values as a result of performance improvements and cost reductions. Even with these improvements, the solar portion of ISCCS plants will produce power that is more expensive than a combined cycle plant.

The potential for STPP to compete with Rankine cycle plants (either coal, gas or oil) is promising. In the long-term, the LEC cost for Trough Rankine plants will be within the expected range for conventional power plants. If a credit is included for reduced carbon emissions, all STPPs have a lower LEC than coal-fired Rankine plants.

PART B:

STRATEGY AND IMPLEMENTATION PLAN

9. INTRODUCTION TO PART B

In Part A of this report it was shown that in the mid to long-term, solar thermal power plants can provide power at a cost that is competitive with conventional electricity generating plants. The economics look best when competing with peaking or older fossil-fuel plants and look less promising when competing with new high-efficiency combined cycle gas plants. While there may be some niche cases where STPPs are cost effective today, a strategic development program is need to commercialize this technology for the more broad-based electricity market. If a development program is not pursued the result will be a lost opportunity to simultaneously respond to a growing demand for electricity supply while contributing to reduced levels of carbon emissions.

Part B presents the strategic development plan. Consistent with the scope of this study, the following areas are addressed:

- Market Development Strategy
- Assessment of the Commercialization Gap
- The Proposed Development Phases
- GEF Entrance and Exit Strategy
- Conclusion & Next Steps

10. MARKET DEVELOPMENT STRATEGY

10.1 MARKET DEVELOPMENT STEPS

A general characterization of the market diffusion for STPPs (or most technologies) is as follows:

1. Research and Development: New technology is explored at a small scale and evaluated for the potential to be significantly better than existing approaches.

2. Pilot scale operation: System level testing of components provides proof of concept and validates predicted component interactions and system operating characteristics. The size of operation is sufficient to allow reliable engineering scale-up to commercial size applications.

3. Commercial validation plants: Construction and long-term operation of early projects in a commercial environment. Operation of these projects validates the business and economic validity of the design, and provides an element of economic risk reduction that goes beyond that which is accomplished at pilot scale operations.

4. Commercial niche plants: Sales of technology into high-valued market applications that supports the technology costs. Costs are reduced due to learning effects, manufacturing economies of scale, and sustaining product improvements.

5. Market expansion: As cost decreases and other attributes improve, sales become possible in a broader range of market applications. The expanded market further reduces cost.

6. Market acceptance: The technology becomes competitive with conventional alternatives and becomes the desired choice in its market. The cost of the technology levels out and the market reaches maturity.

In examining this market diffusion model, Steps 1-3 focus on design validation and risk reduction. These steps are outside of the main role of the GEF. STPPs are beyond these first three steps, with the exceptions of central receivers and thermal storage for trough systems. The objective of GEF support would be to move STPPs through Steps 4 to 6, referred to as Phases 1, 2 and 3 in this report.

10.2 MARKET BARRIERS

To develop a plan for market expansion, it is necessary to understand the barriers STPPs face and must overcome.

Dormant Industry: Although the construction of STPPs was active in southern California in the 1980s, there has been no new construction activity since then. The capability to construct the solar collectors needed in STPPs still exists at companies such as Pilkington Solar (Germany), SOLEL (Israel), and IST (U.S.) but these organizations will have to re-activate or scale-up production lines. As a result there will be an initial cost premium for the solar equipment and these companies may be hesitant to invest in new production processes unless a sustainable market is foreseen.

High Capital Cost: Perhaps the largest impediment to the purchase of STPPs is the high capital cost relative to conventional fossil-fuel plants. In the short term, the capital cost of STPPs will be 2.5 to 3.5 times the capital cost of conventional plants. Longer term projections call for this difference to fall to approximately two times. At that time, the higher capital cost of STPPs is expected to be compensated by the savings in fuel costs and credits for carbon reductions, making the STPPs competitive with conventional systems.

New Technology/Risk of Failure: Although STPPs have had a reasonably successful record of operation for almost twenty years in southern California, many potential purchasers will view STPPs as a new technology. With any new technology there is a risk of failure or not performing up to expectations. New purchasers will also experience one time start-up costs associated with system design, grid integration, training, and setting up of operating procedures. Thus, even if STPPs were equal in cost to conventional power plants, there would be some resistance to switch to this new technology.

Regressive Tax or Financial Policies: Some countries have financial policies that will slow the adoption of STPPs. For example, Brazil applies a high duty on all imports including solar equipment, whereas imported fuels for conventional power plants are usually not subject to duties. Given the current small market for STPPs, it is not economically justified to have solar collector production facilities in each country. In establishing a support program for STPPs, it is important that funds go towards commercializing the technology and not into a country's general revenues.

10.3 STRATEGIC OBJECTIVES

The longer-term objective is the attainment of commercial competitiveness for STPPs vis-à-vis conventional electricity generation systems. Attainment of this objective will enable governments, utilities and eventually the private sector, to respond to the growing demand for electricity supply in a more environmentally benign manner than available through conventional options.

To meet this objective, it will be necessary to effectively address and overcome the market barriers identified above. In the short term, two of those market barriers are particularly critical, namely:

Dormant industry – The industry development process must be rekindled.

Cost – Through a next round of STPP construction, experience must verify that continued cost and performance improvements can meet the forecast levels

11. THE STPP COMMERCIALIZATION GAP

Part A of this report showed that STPPs are predicted to achieve cost parity with conventional peaking power plants in the long term. Until cost parity is achieved, financial support will be required to bridge the cost difference between STPPs and conventional power plants. This section defines the range and timing of the financial commitment.

The STPP commercialization gap is the investment that must be made to reduce the difference in levelized energy cost between STPPs and conventional peaking power plants to zero. There are four possible scenarios for the commercialization gaps depending on the capacity factor of the peaking power plant and whether credit is given for reduced carbon emissions. These are

- Low conventional electricity cost and no credit for carbon reductions,
- Low conventional electricity cost but credit given for carbon reductions,
- High conventional electricity cost and no credit for carbon reductions, and
- High conventional electricity cost but credit given for carbon reductions.

The low electricity cost, based on intermediate load power, is 4.3 cents/kWh. The high electricity cost is 6.9 cents/kWh and is based on peak load power (25% capacity factor). Part of the higher cost for peak load power (0.5 cents/kWh) is the increase in O & M costs because the fixed O & M costs are spread out over fewer kilowatt-hours. These higher fixed costs would also apply to the solar plant. So to ensure a fair comparison the solar LEC values generated for a 50% capacity factor were increased by 0.5 cents/kWh to account for the higher O & M costs if the solar plant were operated for fewer hours (on fossil-fuel). The carbon credit is $25/tonne of carbon, which equates to almost two cents per kilowatt-hour.

Figures 11.1 to 11.4 show the expected decrease in solar LEC with installed capacity. The solar LEC curve was generated using the current cost performance values for the most commercially mature system (Case 4 - 200 MW Rankine trough solar plant) and a progress ratio of 0.88 (see Section 6.3). The future LEC curve would be similar regardless of which solar option was studied because all solar systems options (e.g., thermal storage, central receivers) have similar long-term values of solar LEC (although the uncertainty would be larger for other systems because they are not as commercially mature). It is the shape of the curve that is important rather than which solar technology will emerge as the least cost option.

Table 11.1 summarizes the results from Figures 11.1 to 11.4 and presents the incremental investment required to achieve cost parity for each scenario. The investment is divided into two parts: investment justified by the reduction in carbon emissions and additional investment beyond the carbon credit required to achieve cost parity. The parity target is the cost that solar

Figure 11.1 Scenario 1 – Low conventional electricity cost and no credit for carbon reductions

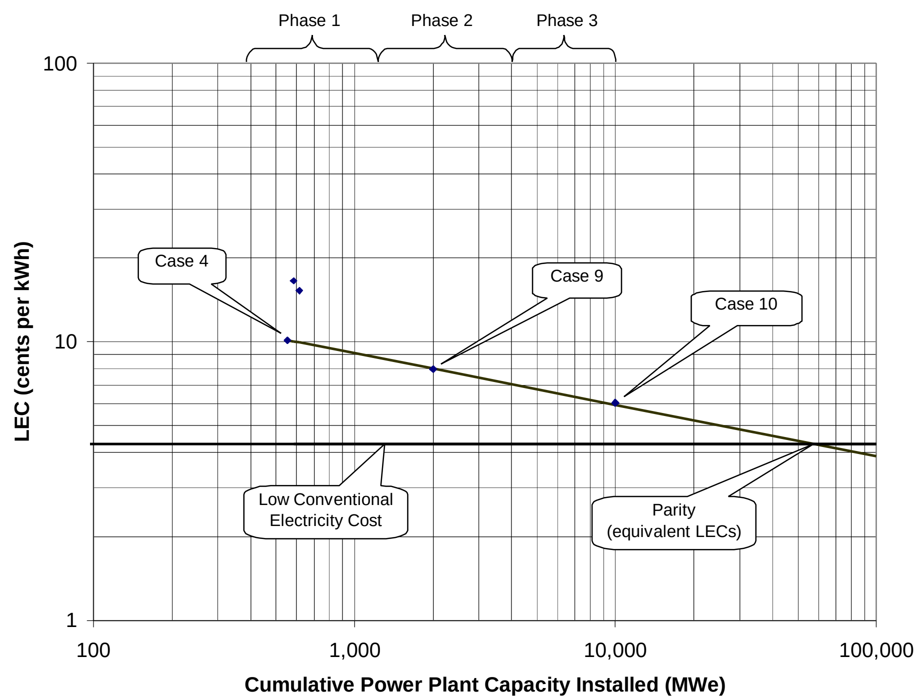


Figure 11.2 Scenario 2 – Low conventional electricity cost with credit given for carbon reductions

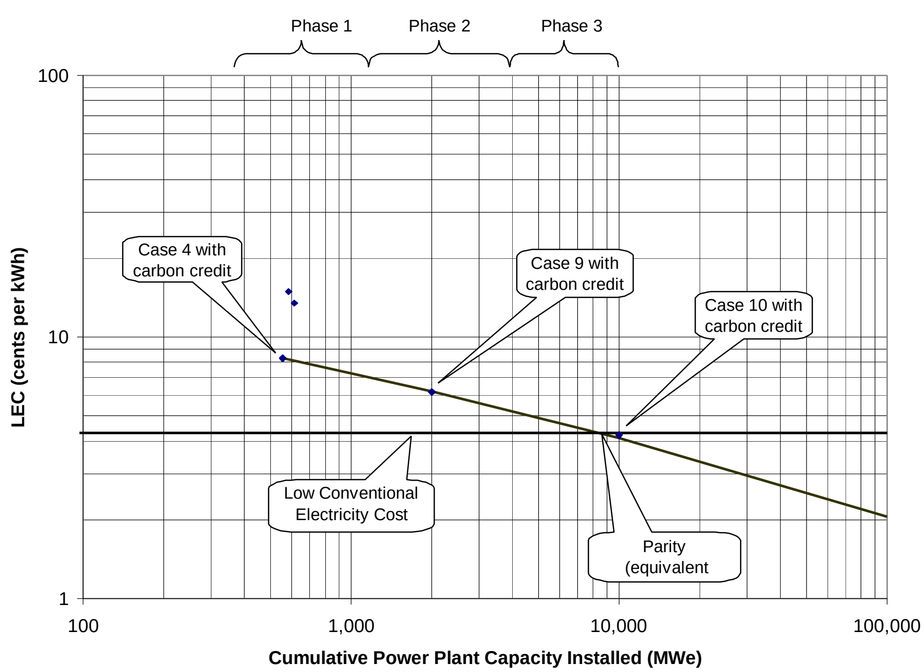


Figure 11.3 Scenario 3 – High conventional electricity cost and no credit for carbon reductions

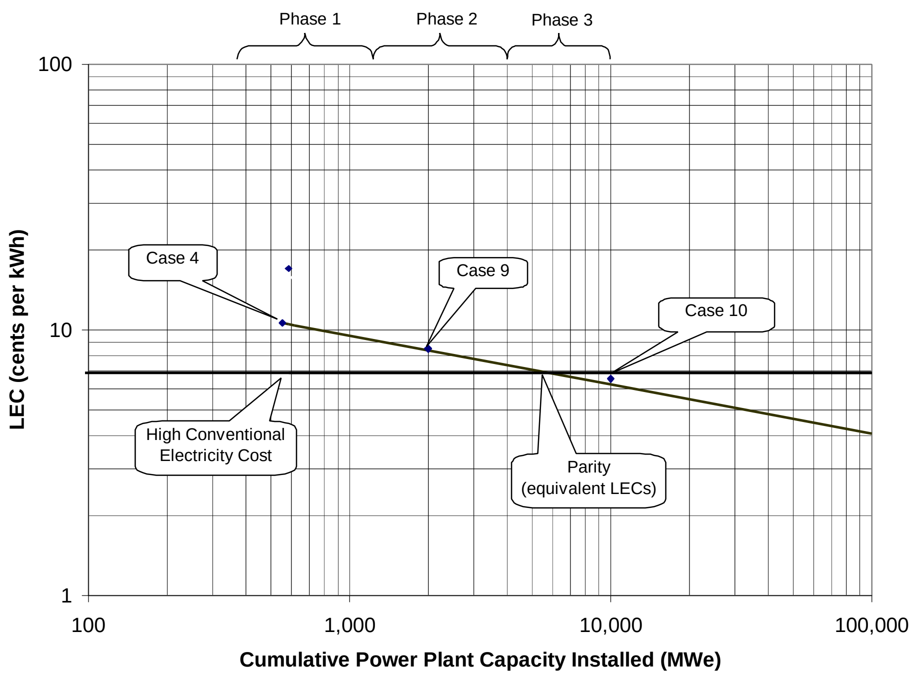
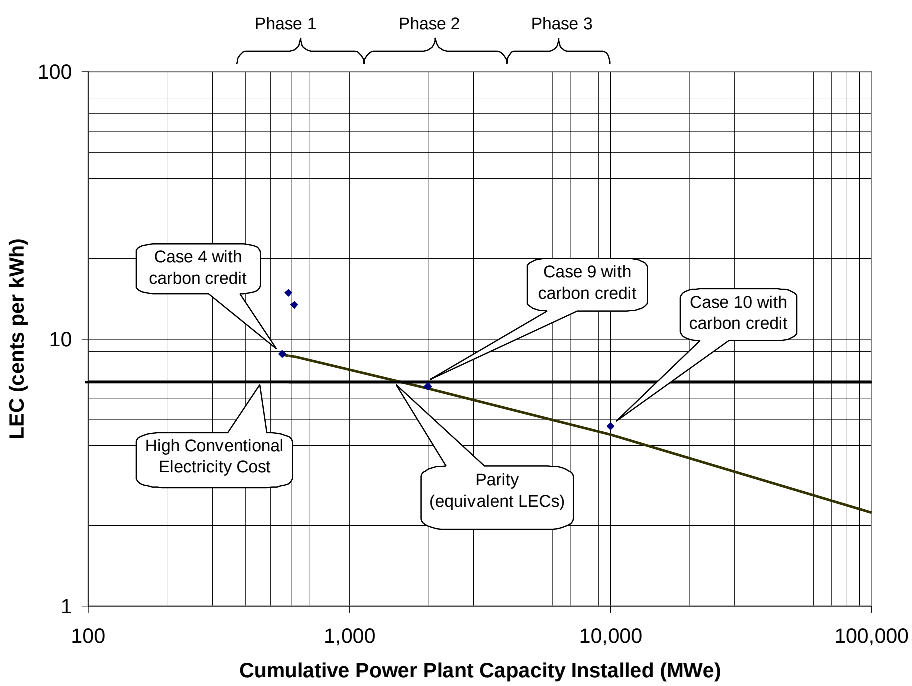


Figure 11.4 Scenario 4 – High conventional electricity cost with credit given for carbon reductions



power must achieve to compete with conventional power. For the scenarios with carbon credits, it is assumed that the STPP carbon savings can be used to buy down the cost of solar power.

There is a wide range in the total incremental level of investment to achieve cost parity from $0.5 billion to $9.7 billion. Scenario 1 is pessimistic since it assumes no carbon credits will emerge and no niche markets with high electricity costs can be identified. If future society is unwilling to pay for reductions in carbon emissions, then the whole role of the GEF is in question. This scenario does show, however, that STPPs will likely need carbon credits to compete with conventional electricity production.

Assuming a market for carbon credits develops, then Scenarios 2 and 4 bracket the range of investment to achieve cost parity. The total incremental investment is between $0.5 and $4.1 billion, however, two-thirds of this investment is a financial recognition of the carbon reduction benefit of STPPs. The incremental investment to achieve cost parity beyond carbon credits is between $0.13 and $1.43 billion. There may be a need for additional funding (perhaps 10%) to compensate for investor risk and to study the progress in achieving program goals.

The goal of the development plan is to reduce solar LEC to under 8.7 cents/kWh to compete with peak electricity power and to under 6.1 cents/kWh to compete with intermediate load power. Since the total potential market for STPPs is estimated at 600,000 MW, only a 1.5% penetration rate over the next 20 years is needed to achieve the lower cost parity target.

Table 11.1 STPP Investment Scenarios

Scenario	Parity Target ¢/kWh	Req'd Capacity (MW)	# of plants @ 200 MW	Carbon Credit $ billions	Additional Incremental Investment $ billions	Total Incremental Investment $ billions
<u>Scenario 1-Worst Case</u> No carbon credit & lowest elec. price	4.3	58,000	290	$0	$9.7	$9.7
<u>Scenario 2</u> Carbon credit & lowest elec. price	6.1	8,700	42	$2.7	$1.43	$4.1
<u>Scenario 3</u> No carbon credit & highest elec. price	6.9	5,700	27	$0	$1.15	$1.2
<u>Scenario 4 – Best Case</u> Carbon credit & highest elec. price	8.7	1,620	6	$0.4	$0.13	$0.5

12. PROPOSED DEVELOPMENT PLAN

12.1 OVERVIEW

The proposed STPP development plan is divided into three phases:

Phase 1 - Niche Market Awareness (near-term)

Phase 2 - Market Expansion (medium-term), and

Phase 3 - Market Acceptance (longer-term).

As is outlined below, each of these phases has different technological, financial and commercialization objectives. The goal of the first phase is to rekindle interest in the technology and increase awareness of several promising STPP options. The goal of the second phase is to scale-up production and plant size to achieve performance increases and cost reductions. In the final phase, the goal is for the technology to achieve cost competitiveness with main stream conventional power plants.

The proposed role of the Global Environment Facility (GEF) would vary in each phase. GEF support is most critical to Phase 1. Based on the study's findings to date, it is believed that without GEF support for Phase 1, further development will not occur. However, at the conclusion of Phase 1, additional options and potential contributors are expected to emerge.

As discussed in the following text, careful evaluation of the results of Phase 1 is essential. In the worst case scenario, GEF may choose to exit at the conclusion of Phase 1 if the results of this additional STPP capacity do not show that the actual STPP cost and performance improvements are within the forecast levels. Alternately, in the more optimistic scenario, if the actual results fall within, or better than, the forecast levels, then it is expected that additional financing will become available that will enable the GEF to gradually withdraw its financial contribution.

The remainder of this section provides further discussion of each proposed phase of the Development Plan. The discussion of each phase is structured as follows:

- Specific Development Objectives
- Target Systems
- Target Markets
- Required Investment Levels
- GEF Role and Exit Strategies

12.2 PHASE 1 – MARKET AWARENESS

12.2.1 Phase 1 Objectives

The Phase 1 objectives are to:

- rekindle interest in STPPs in relevant developing countries,
- allow the industry to start-up production processes,
- determine the current cost and performance of STPPs, and
- evaluate new STPPs concepts to see if they have promise for long term commercialization.

To meet these objectives requires a concerted and regionally diverse market awareness phase.

12.2.2 Target Systems – Phase 1

Since the last SEGS plant was built in 1990, many concepts to improve the cost performance of STPPs have been developed, but not evaluated at the commercial plant scale. The cost performance of solar Rankine cycle plants can be improved by increasing the plant size to 200 MW, and, in the longer term, tilting the arrays towards the sun and adding thermal storage. Methods of integrating the solar field with conventional combined cycle plants have been proposed by Pilkington [1996], Bechtel [1998] and York Research Corporation [1998]. These systems offer lower solar power costs and reduced risk. Testing at Solar Two has shown that the concepts of central receiver and solar thermal storage are technically feasible but they have yet to be evaluated in a true utility setting. If STPPs are to move down the cost performance curve, it is essential that these new concepts be evaluated in commercial-scale power plants.

The main activity for Phase 1 is to increase market awareness by funding one or two STPPs in each region of interest (Mexico, Brazil, North Africa, Southern Africa, Middle East, and India/Pakistan), or approximately nine projects. These systems will likely be smaller than the optimum of over 200 MW because of the need to minimize investor risk and to start-up production processes. Assuming an average solar plant size of 80 MW, the demonstration phase would cover the installation of approximately 750 MW of solar power.

Ideally the awareness campaign should fund several different STPP concepts so that their technical and financial viability can begin to be assessed. It is recommended however, that funding or support programs be technology neutral. The choice of system type and size should be made by the local country and the developer. In this way, the market place can begin to point to the "winning technologies", thereby avoiding spending support dollars on "dead-end technologies". Concepts that are less developed (e.g., central receivers, trough systems with storage) may require research and development support from governments or industry but this is outside the role of the GEF.

12.2.3 Target Markets – Phase 1

In this Phase 1, it is recommended that the initial market focus should be in those markets where the conditions for STPPs are currently most promising. Previous experience shows that these conditions are:

High Solar Resource: The performance of STPPs will be highest in sunny regions. In Section 2.2, suitable regions for STPPs are identified. Within these regions, the solar resource varies from 1700 to 2900 kWh/m^2. Those regions with a solar resource in the upper half of this range will have the best performance. These regions in developing countries include northern Mexico, Egypt, Jordan and other parts of the Middle East.

High Fossil-Fuel Prices: STPPs will have the largest cost savings when displacing high cost fuels, such as diesel, oil and naphtha. These fuels are used in Morocco, Crete and India. Coal, although a low-cost fuel, has the highest pollution emissions. The credit for reduced carbon emissions will more than offset the low cost of this fuel.

Daytime Peaking Utility: In most developing countries, the peak electricity demand is in the 5 pm to 11 pm period. This peak is shifting however, to earlier in the day as air-conditioning loads are added to the system. In northern Mexico, for example the peak is at 3 pm (see Figure 2.2). As this shift occurs the output from the solar plant can be used to displace peak electricity generating plants. The solar power is thus competing against more expensive conventional power. Utilities in developing countries typically have a requirement for 10 to 15% of the system capacity for peak power and another 10 to 15% for intermediate power.

Inefficient Conventional Power Plants: New combined cycle natural gas power plants can have efficiencies of over 50%. However, most utilities have a mixture of power plants. STPPs will look most favorable when displacing either older power plants or Rankine or combustion turbine plants operated to meet the peak electrical load.

Local Support for STPPs: Several countries are supportive of STPPs. Rather than placing import duties or trade barriers on solar equipment, these countries are encouraging the adoption of this more environmentally appropriate technology. For example, Spain is willing to pay a premium for solar generated electricity and the European Union is supporting the project in Crete.

Access to Water and the Grid: Power plants (whether solar or fossil fuel) need water for cooling and access to the electric grid (to transmit the power to the load). While at first it may seem a challenge to have access to water in sunny arid regions, most regions being considered for STPPs border a large body of water. Thus, access to water and the grid is essentially a local siting issue.

The Phase 1 STPP installations should target those regions where several of the above conditions are met.

12.2.4 Required Investment – Phase 1

Because this is the start-up (or re-starting) phase of STPPs, the funding requirements for these projects will be high on a $/kW basis. The total dollar investment is less than Phase 2 (see Section 12.3) because only a few projects are funded. Because there is no system in place for selling or trading carbon credits, financial support will have to cover the full cost differential between STPPs and conventional power. Depending on the cost of power displaced, the financial support to achieve cost parity will range from $400 to $750 million or $550 to $1000 per kW. An additional payment (perhaps 10%) may be required to compensate for the risk of these first few systems.

12.2.5 Proposed GEF Role and Exit Strategies – Phase 1

The support funding for this Phase 1 will have to come almost entirely from the GEF. No other funding agency has emerged in the nine years since the last STPP was built. Thus, the GEF has to show a commitment to this technology in order to encourage other funding agencies to come forward and to convince the private sector that there is a market for STPPs.

The implementation strategy would have the GEF fund the full incremental cost for the first four projects. These would likely be the projects that have been submitted for GEF funding. The remaining five projects would be selected through an open solicitation based on the lowest funding request (per kWh). Proponents would be encouraged to locate the best applications for STPPs, develop the most cost-effective systems and solicit support from other organizations. This technique may allow the GEF to reduce their level of financial support.

A final aspect of this phase is performance monitoring. Because new concepts are being tried, it is important the cost, performance and reliability of the systems be documented and shared with the solar thermal community. This exchange of information will help to identify problems that need to be corrected.

The assessment of STPP progress to the end of Phase 1 will provide the basis for the GEF's first exit decision. As outlined previously, the solar (not total plant) levelized energy cost are forecast to be in the range of 10 to 11 cents/kWh (for a 200 MW system). The actual cost and performance data from Phase 1 installations will, therefore, provide a readily measurable indicator of progress to date. If the cost of solar power is significantly above these values (corrected for size of system – see Figure 3.2), then the GEF should reconsider future support. If on the other hand, the cost per kilowatt-hour is equal to or below this value, then Phase 2 should proceed.

12.3 PHASE 2 – MARKET EXPANSION

12.3.1 Phase 2 Objectives

Once STPPs have been demonstrated in the regions of interest, the next phase in the development process is to scale-up the technology and expand the market. The purpose of the market expansion phase is:

- develop larger systems to benefit from economies of scale,
- continue with product development to improve performance and lower costs,
- create a market large enough that manufacturers can justify construction of production lines, and
- standardize system designs.

The desired result for this phase is to lower the solar LEC so that STPPs can compete with conventional power assuming a carbon market develops. This means that the solar LEC must fall to approximately 7.5 cents/kWh.

12.3.2 Target Systems – Phase 2

Most of the projects that have been submitted to the World Bank/GEF for support are smaller (30 to 100 MW) than the optimum size (200 MW or more). While it makes sense in the demonstration phase to evaluate modest size systems, in the scale-up phase the size of the systems should be increased to benefit from economies of scale. It has been estimated that for each doubling of plant size, the system cost falls by 12% [Pilkington, 1996]. By the time system size has reached 200 MW most of the economy-of-scale benefit has been achieved.

As the systems reach an optimum size, there will be a tendency to standardize the system design. A standard design will help to improve the system cost performance by reducing design costs, streamlining equipment procurement and minimizing construction and start-up problems. There will also be a need to standardize and make widely available design and site selection tools, so that utility planners and designers can evaluate the solar option.

The results of the market awareness phase will identify areas for potential improvement in system performance and opportunities for cost reductions. It is important in the scale-up phase to continue with research, development and demonstration of STPPs. Possible improvements in this phase are better performing mirror and receiver coatings, development of thermal storage systems for parabolic troughs, direct steam generation in the collectors and better integration with the balance of plant.

Perhaps the most important goal in this phase is to increase market demand so that a STPP industry can develop. Today, there are only a handful of collector manufacturers and STPP project developers. As the market increases, the existing players will be able to scale-up their operations and new players will enter the market. This will drive down costs for two reasons. First, manufacturers will be able to justify expenditures into more efficient production lines. Second, new players will introduce competitive pressures to lower costs and improve performance.

12.3.3 Target Markets –Phase 2

In this phase, 3000 MW of additional solar capacity is installed, or fifteen 200 MW plants. The cost of solar power is expected to fall from over 10 cents/kWh to between 7 and 8 cents per kWh. At this price level, STPPs should be able to provide power at a cost competitive with conventional sources if credits are given for carbon reductions. As the cost of the technology falls, the market for STPPs should move beyond niche applications and open up to peak load applications regardless of the conventional fuel source.

12.3.4 Required Investment Levels – Phase 2

This phase represents an increased investment over Phase 1 and in some scenarios the largest investment. Depending on the cost of power displaced, the financial support to achieve cost parity will range from $0.5 to $1.8 billion or $350 to $600 per kW.

12.3.5 GEF Role and Exit Strategies – Phase 2

New funding partners may emerge in the market expansion phase provided the World Bank/GEF continues to show their support for this technology. Possible other funding partners include the OECF and the KfW. Given these various alternative funding sources, it is assumed that the GEF will be able to reduce their level of support from close to 100% in the market awareness phase to an average of 50% in this phase. Thus, the level of GEF support will range from $250 to $900 million.

In addition, more countries may follow Spain's lead and pay a premium for solar generated electricity or penalize carbon-emitting energy technologies. Some developed countries (especially those with local solar collector manufacturing plants) may provide support to solar projects as part of their international aid package to developing countries.

The assessment of STPP progress to the end of Phase 2 will provide the basis for the GEF's second exit decision. The solar levelized energy cost are forecast to be in the range of 7 to 8 cents/kWh at the end of this phase. If the cost of solar power is significantly above these values, then the GEF should reconsider future support. If on the other hand, the cost per kilowatt-hour is equal to or below this value, then Phase 3 should proceed.

12.4 PHASE 3 – MARKET ACCEPTANCE

12.4.1 Phase 3 Objectives

The final part in the development plan is the market acceptance phase. The goal for this phase is to set up the necessary market structure so that STPP can compete with conventional power plants without financial support from the GEF or others.

12.4.2 Target Systems and Markets – Phase 3

As the solar option matures, STPPs will compete in the broad electricity market and not just niche markets. With decreasing costs, STPPs will displace intermediate electricity loads and perhaps base load in regions with high fuel costs. It is expected that STPPs will be designed to have higher capacity factors and operate more as stand-alone systems.

12.4.3 Required Investment Levels – Phase 3

The investment requirement in this phase is the most difficult to estimate and subject to the widest variation. The cost of solar generated electricity is expected to fall close to conventional power values. A small difference in solar costs can have a huge impact on the market penetration. Similarly, the existence of carbon credits will have major impact on the market acceptance of STPPs.

If there is a program of carbon credits or trading, STPPs will likely not require any support from the GEF under the high conventional energy cost scenario. Under the low conventional energy cost scenario, an investment of $330 million would be required (beyond the credit for carbon emission reduction). This translates into $100/kW. After this STPPs should be able to compete without any financial support.

Without a program for carbon credits a significant support program may be required to achieve cost parity. If a carbon market does not develop in the long-term, this implies society does not place a value on reducing greenhouse gas emissions. In this scenario, there is no role or need for the GEF and the GEF would not be required to support STPPs or other technologies that reduce greenhouse gases.

12.4.4 Role of GEF and Exit Strategies – Phase 3

Assuming successful Phases 1 and 2, the market acceptance phase is expected to lead to cost parity of STPPs with conventional fossil fuel plants, particularly if carbon credits are available. The most important role the GEF can provide in this phase is to encourage the adoption of carbon credits. If successful, only modest financial support from the GEF would be required in this phase. This provides the final exit strategy for the GEF.

The success of the commercialization will depend on several factors. First and most importantly is whether the cost and performance goals for STPPs are met. Second, cost parity is based on a financial credit for reduced carbon emissions. If there is no carbon trading, carbon credits or carbon tax, the adoption of STPPs will be reduced or slowed. Third, trade, tax and other economic barriers must not penalize the solar option. The study was performed as an economic analysis, not a financial analysis. Real-life financing issues can have a major impact on the adoption of any technology.

The GEF can play a major role in all three of these areas, ensuring that a cost-effective technology is developed, a program of carbon credits or trading is implemented and financial barriers are limited. The next section specifically defines the next steps in realizing the potential for solar thermal power plants.

12.5 SUMMARY

Table 12.1 summarizes the requirements for each of the three phases in the development plan. The total investment for the GEF is estimated at $600 million to $1.75 billion for the three phases (assuming a carbon market develops by Phase 3). This corresponds to an annual investment of between $60 and $160 million per year over the next ten years.

Table 12.1 Required Investment in STPPs by Phase[1]

Phase	Time Frame	Solar LEC Target (c/kWh)	Additonal Installed Capacity	Est. Total Incremental Investment ($ million)	Est. GEF Investment ($ million)
Phase 1	2000 – 2004	10 to 11	750 MW	440 to 750	350 to 700
Phase 2	2005 – 2009	7 to 8	3000 MW	500 to 1,800	250 to 900
Phase 3	2010 +	Under 6	4600 MW	0 to 330[1]	0 to 150[1]
Total			**8300 MW**	**940 to 2,955**	**600 to 1,750**

[1] – assumes a carbon market develops by Phase 3

13. THE NEXT STEPS FOR THE WORLD BANK/GEF

The GEF is poised to play a key role in the development of STPPs. The key steps to be undertaken are listed below.

Provide specific guidance to industry on GEF involvement in commercialization of STPP. The GEF needs to provide specific information to industry on the role that the GEF intends to play in commercializing this technology. This will help both industry and governmental R&D organizations target their activities. Indications of the desire to play a long-term role would reduce the risk to industry for making investments in developing the technology.

Use current role as an advocate for STPPs. The GEF and World Bank are looked to around the world as the key organization today essential for commercial deployment of STPP technology. Promoting this technology to governmental organizations and the private sector around the world will help increase interest in this technology.

Establish consultation role between Bank, industry and R&D Organizations. The World Bank and GEF should coordinate their activities with industry and R&D organizations. The World Bank is in a position to provide their perspectives on market trends that could be highly valuable to industry and R&D organizations. Similarly, World Bank and GEF initiatives should be flexible enough to take advantage of new developments in the technology.

Establish cost reduction targets for providing support. The GEF should establish a program that provides reducing contributions with installed capacity. The contributions are based on the achieving certain cost performance goals. This approach would focus industry on developing cost-effective applications and systems. Another benefit of the approach is that it would provide an exit strategy for the GEF. If cost performance goals are not met, then GEF support should be curtailed.

14. CONCLUSIONS TO PART B

A three-phase development plan is required to commercialize STPPs: market awareness, market expansion and market acceptance. GEF support is critical to the success of this plan.

In Phase 1, the GEF would need to provide financial support in the order of $350 to 700 million to fund approximately nine projects (750 MW). The support would be in the range of $550 to $1000/kW.

In Phase 2, a further 3,000 MW of installed capacity would be supported. The total support cost is estimated at $500 million to $1.8 billion ($350 to 600/kW). Additional financial partners are expected to emerge, so that GEF support would only be a portion of these values.

In Phase 3, the emergence of carbon credits could mean that STPPs are cost effective and only modest financial support is required (less than $330 million). The total support required to commercialize STPPs is estimated at between $1 and $3 billion; approximately 60% of which would need to come from the GEF. The annual GEF investment is estimated at between $60 and $160 million.

The success of the commercialization will depend on several factors. First and most importantly is whether the cost and performance goals for STPPs are met. The goals are 10 to 11 cents/kWh at the end of Phase 1, 7 to 8 cents/kWh at the end of Phase 2 and under 6 cents in Phase 3. Second, cost parity is based on a financial credit for reduced carbon emissions. If there is no carbon trading, carbon credits or carbon tax, the adoption of STPPs will be reduced or slowed. Third, trade, tax and other economic barriers must not penalize the solar option. Real-life financing issues can have a major impact on the adoption of any technology. The study was performed as an economic analysis, not a financial analysis.

The GEF can play a major role in all three of these factors, ensuring that a cost-effective technology is developed, a program of carbon credits or trading is implemented and financial barriers are limited.

15. REFERENCES

Anderson, 1998. The Economics of Photovoltaic Technologies. Paper prepared by Dennis Anderson, Imperial College of Science, Technology and Medicine for the World Bank

Bohn, 1995. Combined Cycle Power Tower. *Proceedings of the 1995 ASME/JSME/JSES International Solar Energy Conference, March 19-24, 1995*. Prepared by M. Bohn, T. Williams, H. Price.

Cordeiro, 1997. START Mission to Brazil – May 5-9, 1997. Prepared for International Energy Agency (IEA) Solar Power and Chemical Energy Systems. Prepared by Patricia Cordeiro, Sandia National Laboratories, Albuquerque, New Mexico.

DOE/EPRI, 1997. Renewable Energy Technology Characterizations. Prepared by EPRI and U.S. Department of Energy. Palo Alto, California and Washington, D.C.

DOE, 1998. Annual Energy Outlook 1999 – Electricity Market Module. Prepared by the U.S. Department of Energy, Washington, D.C.

Fichtner Development Engineering, Engineers India Ltd., 1995. Comprehensive Feasibility Report – Solar Thermal Power Plant – Mathania Rajasthan. Prepared for Rajasthan Energy Development Agency.

Geyer, 1996. IEA Solar PACES START Mission to Egypt – February 23-29. 1996. Prepared for Ministry of Electricity & Energy, New & Renewable Energy Authority. Edited by Dr. Michael Geyer, Alméria.

Geyer, 1997. START Mission to Jordan – March, 1997. Prepared for International Energy Agency Solar Power and Chemical Energy Systems. Prepared by Michael Geyer and Rainer Kistner, Alméria.

ISCCS, 1998. Integrated Solar Combined Cycle System Subcontract ADC – 8-18466-01 Final Report. Prepared for National Renewable Energy Laboratory. Prepared by Bechtel Corporation, San Francisco, California

IEA, 1991 "*Guidelines for The Economic Analysis of Renewable Energy Technology Applications*"

International Private Power Quarterly, 1998. Egypt. Fourth Quarter 1998.

Kolb, 1997. Economic Evaluation of Solar-Only and Hybrid Power Towers Using Molten-Salt Technology. Prepared for Elsevier Science Ltd., Great Britain. Prepared by Gregory J. Kolb, Solar Thermal Technology Department, Sandia National Laboratories, Albuquerque, New Mexico.

Lewis, 1996. India's Refining Prospects Linked to Economic Growth. June 10, 1996, *Oil and Gas Journal*.

Neij, 1997. Use of Experience Curves to Analyse the Prospects for Diffusion and Adoption of Renewable Energy Technology. *Energy Policy, 1997,* Elsevier Science Ltd., Great Britain.

Pilkington, 1996. Status Report on Solar Trough Power Plants. Prepared for the German Federal Ministry for Education, Science, Research and Technology. Prepared by Pilkington Solar International GmbH, Cologne, Germany.

Pilkington, 1998. Prefeasibility Study – Solar Thermal Trough Power Plant for Northern Morocco. Prepared for the European Commission Directorate General 1, INFRAST/ME1/B74100/96/002/A5. Prepared by Pilkington Solar International GmbH with contributions from INTEC, Cologne, Germany.

Spencer Management Associates, 1994. Integrated Solar Combined Cycle Systems (ISCCS) Using Solar Parabolic Trough Technology – Phase IA Technical and Economic Review. Prepared for Sub-Secretario de Electricidad Parastate Department of Energy, Mines & Industry (SEMIP), Gerente de Proyectos Geotermoelecticos Comision Federal de Electricidad (CFE), The Rockefeller Foundation, The World Bank. Prepared by Spencer Management Associates, Diablo, California.

World Bank, 1998. Commodity Markets and the Developing Countries. Prepared by the World Bank, Washington, D.C.

Appendix A. Sample Calculation of Levelized Electricity Cost

Calculation Inputs

Tables A.1 shows the inputs for Case 5, a 200 MW Trough Rankine system. Table A.2 gives an explanation of the various inputs and assumptions made to establish the base values for each case. The input data for capital costs, O&M costs and performance variables are extracted from the values in Section 3.

Table A.1 Inputs for Case 4: 200 MW Trough Rankine

Plant parameters: 200 MW Trough Rankine	Quantity	Units
Qualitative		
Date of analysis	19-Feb-99	
Plant identification	Case 4	
Plant type	Rankine	
Concentrator type	Trough	
Expected system lifetime	25	years
System Description		
Total plant power (nominal)	200	MWe, net
Solar component power (nominal)	200	MWe, net
Thermal Energy Storage	n/a	MWhe
Concentrator Aperture Area	n/a	m^2
Installed Cost		
Total Investment	413,950	000 USD
Grant for non-conventional fraction	-	000 USD
Grant for conventional fraction	-	000 USD
Annual O&M cost	8,191	'000 USD/yr
Economic parameters		
Annual discount rate	8.0%	
Annual insurance rate	1.0%	
Efficiencies		
Heat collection efficiency	44.2%	
Power cycle efficiency	38.0%	
Parasitic efficiency	85.5%	
Solar-to-Electricity Net efficiency	14.4%	
Annual solar efficiency	13.0%	
Plant capacity	50.0%	
Solar capacity (apparent)	25.1%	
Solar capacity (real)	25.1%	
System Performance		
Net electricity to grid	876,000	MWhe/yr
Net electricity by solar	439,752	MWhe/yr
Net electricity by fuel	436,248	MWhe/yr
Full load hours - total	4,380	h/yr

Fuel		
Baseline Fuel (Coal or Gas)	Coal	
Fuel cost	1.14	$/GJ
Annual CO_2 credits	0	USD per tonne
Specific emissions	0.827	Tonnes CO_2/MWhe
	0.226	Tonnes C/MWhe
Net conversion efficiency for fuel (HHV)	35.5%	
Net conversion for solar backup (HHV)	30.7%	
Emissions data / base case		
Base Case (Coal Rankine or Combined Cycle)	Coal Rankine	
Specific emissions of base case	0.827	Tonnes CO_2/MWhe
	0.226	Tonnes C/MWhe
Capital cost	864.45	USD/kW
Annual plant efficiency	34.4%	
Annual O&M costs	0.731	Cents/kWh

Table A.2 Explanation of inputs for engineering model

Variable	Notes	Value
Expected system lifetime	This is the useful life of the plant	Results are based on 25 year lifetime
Total Plant Power (nominal)	Maximum overall plant output, including both solar and fossil-fuel components	Case-dependent
Solar component power	The maximum output of the solar component. This number is included in the Total Plant Power	Case-dependent
Total Investment	Installed cost for plant including site works, solar field, HTF system etc.	Case-dependent
Annual O&M costs	Annual cost for all operation and maintenance	Case-dependent
Discount Rate	see Table 4.2	Results based on 10% discount rate
Plant Capacity	Percentage of time during year that plant runs at maximum (nominal) power	Set at 50% for all cases
Solar Capacity	Percentage of time during year that the solar component runs at full power	Case-dependent
Fuel costs	Expressed in USD per GJ	1.14 USD/GJ for coal, 2.37 USD/GJ for gas
Specific emissions	Tonnes of CO_2 released as a function of plant power output and power conversion type	0.093 tC/MWh for Gas Combined Cycle, 0.226 tC/MWh for Coal Rankine (Kolb, 1996)
Fuel conversion efficiency	Reflects the energy conversion efficiency of the power plant. The conversion efficiency of a fuel plant in solar backup mode is lower than that of a fuel-only plant	Coal Rankine: - 35.5% fuel-only plant - 28.0% or 30.7% in backup mode Gas Combined Cycle: - 48.3% fuel-only plant - 45.5% in backup mode
Base case data	For STPP ISCCS-type plants, a fuel-only Gas Combined Cycle plant is used for comparison. For STPP Coal Rankine plants, a coal plant is used for comparison	

Calculations for Case 4:

The IEA Methodology is used to calculate the Levelized Electricity Cost. A complete calculation for Case 4 (200 MW Trough Rankine) is shown below to demonstrate the methodology and assumptions.

Levelized Electricity Cost (LEC) calculations

$$(1) LEC_{Plant} = \frac{(FCR \cdot I) + OM + L - C}{E}$$

Where: *FCR = fixed charge rate*

I = Installed capital costs

OM = Annual operation and maintenance costs in year zero

L = Annual expenses for input energy

C = Annual CO_2 reduction credit

E = Annual energy production (Wh)

$$(2) FCR = \sum_{t=1}^{n} \frac{1}{(1+k_d)^t} + p_1$$

Where: *n = Lifetime of the plant (years)*

k_d= discount rate

p1 = insurance rate

$$LEC_{solar} = \frac{LEC_{STPP} - (1 - FS) \cdot LEC_{Con}}{FS}$$

Where: *LEC_{STPP} = LEC of STPP*

FS = solar share (full load hours solar / full load hours plant)

LEC_{Con} = LEC of equivalent conventional plant

Fixed charge rate = using equation (2) at n=25 years and k_d = 8%

= 9.37% + 1.00%

= 10.37 %

Net electricity to grid = Total Plant Power x Plant Capacity Factor x Hours Per Year

= 200 MW x 0.5 x 8760

= 876,000 MWh per year

Solar Capacity factor = Relative Solar Capacity x Solar component power / Total plant power

= 0.251 x 200 MW / 200 MW

= 0.251 (or 25.1%)

Net electricity by solar = Nominal Power x Solar Capacity Factor x Hours per year

= 200 MW x 0.251 x 8760

= 439,752 MWh per year

Net electricity by fuel = Net electricity to grid – Net electricity by solar

= 436,248 MWh per year

Fuel consumed = Net electricity by fuel x (Wh to J Conversion) / Conversion efficiency

= (436,248 MWh) x (3.6 GJ/MWh) / 0.307

= 5,115,612 GJ

Note: 30.7% is the conversion efficiency of a Rankine plant in backup mode.

Annual fuel cost = Fuel consumed x Fuel cost

= 5,115,612 GJ x 1.1.4 USD/GJ

= 5,831,797 USD

Annual O & M cost = O&M cost factor x Net electricity to grid

= (0.935 cents/kWh) / (100 cents/USD) x (876,000 MWh) x

(1000 kWh/MWh)

= 8,190,600 USD

CO_2 emissions (STPP) = Net electricity by fuel x Emissions factor

= 436,248 MWh x 0.827 tonnes CO_2/MWh

= 360,777 tonnes CO_2

Carbon emissions (base) = Net electricity to grid x Emissions factor

= 876,000 MWh x 0.827 tonnes CO_2/MWh

= 724,452 tonnes CO_2

Annual avoided emissions = CO_2 emissions (base) – CO_2 emissions (STPP)

= 724,452 – 360,777

= 363,675 tonnes CO_2/year or 99,184 tonnes Carbon/year

Note: Number different on spreadsheet due to rounding

Cost of avoided emissions = Total Investment / Lifetime avoided emissions

= 413,950,000 USD / (363,675 tonnes CO_2/year x 25 years)

= 45.53 USD/tonne CO_2

Annual CO_2 credits = Annual avoided emissions x Emissions credits

= 363,675 tonnes CO_2 x 0 USD/tonne CO_2

= 0 USD

LEC (entire plant) = ((0.1037) x (413,950,000) + 8,190,600 + 5,831,797 – 0) / 876,000

= 65.01 USD per MWh

LEC (conventional) = [(0.1037) x (864.45 x 200,000) + (0.731 / 100 * 876,000,000) +

(3.6 x 876,000,000/ 0.344 x 1.14 / 1000)] / 876,000

= 39.70 USD per MWh

Note: Because the base case plant runs as a fuel-only plant, its efficiency is greater than that of a backup plant. Thus efficiency = 34.4% rather than 30.7%

LEC (solar) = [65.01 – (1 – 0.502) x 39.70] / 0.502

= 90.10 USD per MWh

Appendix B. Results of LEC Analysis for all Cases

This appendix contains the analysis of the 15 cases studied. The format is similar to that presented in other reports [Pilkington, 1996] so that these results can be easily compared to the results of other studies.

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**1**	**400 MW**	**None**	**Rankine**
Net capacity	400 MW	Solar field	n/a	m^2
Solar capacity	0 MW	Fuel type	Coal	
Summary of base case parameters				
Project cost w/o tax ('000 USD) *	345,780	Expected lifetime	25	years
Grant for non-conventional fraction	-	Annual discount rate	10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate	1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate	12.02%	
Unit cost (USD/kW)	864	CO_2 credits	-	USD/tonne
Efficiencies				
Heat collection efficiency	0.0%	Annual solar efficiency		0.0%
Power cycle efficiency	0.0%	Plant capacity		50.0%
Parasitic efficiency	0.0%	Solar capacity		0.0%
Solar-to-electric net efficiency	0.0%	Plant efficiency (Back-up Mode)		34.4%
Levelised Electricity Cost calculations				
Net electricity by solar			-	MWhe/yr
Net electricity by fuel			1,752,000	MWhe/yr
Net electricity to grid			1,752,000	MWhe/yr
Solar share			0.0%	
Full load hours - total			4,380	h/yr
Full load hours - solar			-	h/yr
Annual fuel use			18,334,884	GJ/yr
Annual fuel cost			20,901.77	'000 USD
Annual O&M cost			12,807	'000 USD
Levelised Electricity Cost (entire plant)			**42.96**	**USD/MWh**
Capital cost fraction			23.72	USD/MWh
Fuel cost fraction			11.93	USD/MWh
O&M cost fraction			7.31	USD/MWh
Solar LEC calculations				
LEC for base case plant of equivalent power; type:		Coal Rankine	42.96	USD/MWh
Capital cost fraction			23.72	USD/MWh
Fuel cost fraction			11.93	USD/MWh
O&M cost fraction			7.31	USD/MWh
LEC (solar only component)			**-**	**USD/MWh**
Avoided emissions calculations				
Electricity production by fuel over lifetime			43,800,000	MWhe
Electricity production - total over lifetime			43,800,000	MWhe
Emissions over lifetime (STPP)			39,374,163	t CO_2
Emissions over lifetime (Base case)		Coal Rankine	39,374,163	t CO_2
Avoided emissions (over lifetime)			**-**	t CO_2
Avoided emissions (annual)			**-**	t CO_2 per year
Avoidance cost (w/o grant) against base case			**#DIV/0!**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**2**		**376 MW**	**None**	**Combined Cycle**
Net capacity	376 MW		Solar field	n/a	m^2
Solar capacity	0 MW		Fuel type	Gas	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	116,974	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	2.63	Fixed charge rate		12.02%	
Unit cost (USD/kW)	311	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	0.0%	Annual solar efficiency			0.0%
Power cycle efficiency	0.0%	Plant capacity			50.0%
Parasitic efficiency	0.0%	Solar capacity			0.0%
Solar-to-electric net efficiency	0.0%	Plant efficiency (Back-up Mode)			53.5%
Levelised Electricity Cost calculations					
Net electricity by solar				-	MWhe/yr
Net electricity by fuel				1,646,880	MWhe/yr
Net electricity to grid				1,646,880	MWhe/yr
Solar share				0.0%	
Full load hours - total				4,380	h/yr
Full load hours - solar				-	h/yr
Annual fuel use				11,081,809	GJ/yr
Annual fuel cost				29,182.10	'000 USD
Annual O&M cost				5,599	'000 USD
Levelised Electricity Cost (entire plant)				**29.65**	**USD/MWh**
Capital cost fraction				8.54	USD/MWh
Fuel cost fraction				17.72	USD/MWh
O&M cost fraction				3.40	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Combined cycle		29.65	USD/MWh
Capital cost fraction				8.54	USD/MWh
Fuel cost fraction				17.72	USD/MWh
O&M cost fraction				3.40	USD/MWh
LEC (solar only component)				**-**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				41,172,000	MWhe
Electricity production - total over lifetime				41,172,000	MWhe
Emissions over lifetime (STPP)				13,763,607	t CO_2
Emissions over lifetime (Base case)		Combined cycle		13,763,607	t CO_2
Avoided emissions (over lifetime)				**-**	t CO_2
Avoided emissions (annual)				**-**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**#DIV/0!**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**3**		**30 MW**	**Trough**	**Rankine**
Net capacity	30 MW		Solar field	n/a	m^2
Solar capacity	30 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	89,123	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	2,971	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	44.2%	Annual solar efficiency			12.5%
Power cycle efficiency	37.5%	Plant capacity			50.0%
Parasitic efficiency	83.6%	Solar capacity			25.0%
Solar-to-electric net efficiency	13.9%	Plant efficiency (Back-up Mode)			31.1%
Levelised Electricity Cost calculations					
Net electricity by solar				65,700	MWhe/yr
Net electricity by fuel				65,700	MWhe/yr
Net electricity to grid				131,400	MWhe/yr
Solar share				50.0%	
Full load hours - total				4,380	h/yr
Full load hours - solar				2,190	h/yr
Annual fuel use				760,514	GJ/yr
Annual fuel cost				866.99	'000 USD
Annual O&M cost				2,569	'000 USD
Levelised Electricity Cost (entire plant)				**107.65**	**USD/MWh**
Capital cost fraction				81.50	USD/MWh
Fuel cost fraction				6.60	USD/MWh
O&M cost fraction				19.55	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		42.96	USD/MWh
Capital cost fraction				23.72	USD/MWh
Fuel cost fraction				11.93	USD/MWh
O&M cost fraction				7.31	USD/MWh
LEC (solar only component)				**172.35**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				1,642,500	MWhe
Electricity production - total over lifetime				3,285,000	MWhe
Emissions over lifetime (STPP)				1,633,205	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		2,953,062	t CO_2
Avoided emissions (over lifetime)				**1,319,857**	t CO_2
Avoided emissions (annual)				**52,794**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**67.52**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**4**		**200 MW**	**Trough**	**Rankine**
Net capacity	200 MW		Solar field	n/a	m^2
Solar capacity	200 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	405,280	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	2,026	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	44.2%	Annual solar efficiency			13.0%
Power cycle efficiency	38.0%	Plant capacity			50.0%
Parasitic efficiency	85.5%	Solar capacity			25.1%
Solar-to-electric net efficiency	14.4%	Plant efficiency (Back-up Mode)			34.1%
Levelised Electricity Cost calculations					
Net electricity by solar				439,752	MWhe/yr
Net electricity by fuel				436,248	MWhe/yr
Net electricity to grid				876,000	MWhe/yr
Solar share				50.2%	
Full load hours - total				4,380	h/yr
Full load hours - solar				2,199	h/yr
Annual fuel use				4,605,551	GJ/yr
Annual fuel cost				5,250.33	'000 USD
Annual O&M cost				8,191	'000 USD
Levelised Electricity Cost (entire plant)				**70.94**	**USD/MWh**
Capital cost fraction				55.60	USD/MWh
Fuel cost fraction				5.99	USD/MWh
O&M cost fraction				9.35	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		42.96	USD/MWh
Capital cost fraction				23.72	USD/MWh
Fuel cost fraction				11.93	USD/MWh
O&M cost fraction				7.31	USD/MWh
LEC (solar only component)				**98.70**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				10,906,200	MWhe
Electricity production - total over lifetime				21,900,000	MWhe
Emissions over lifetime (STPP)				9,890,420	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		19,687,081	t CO_2
Avoided emissions (over lifetime)				**9,796,661**	t CO_2
Avoided emissions (annual)				**391,866**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**41.37**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**5**	**30 MW**	**Trough**	**ISCCS**
Net capacity	30 MW	Solar field	n/a	m^2
Solar capacity	30 MW	Fuel type	Gas	
Summary of base case parameters				
Project cost w/o tax ('000 USD) *	78,872	Expected lifetime	25	years
Grant for non-conventional fraction	-	Annual discount rate	10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate	1.0%	
Fuel price (USD per GJ)	2.63	Fixed charge rate	12.02%	
Unit cost (USD/kW)	2,629	CO_2 credits	-	USD/tonne
Efficiencies				
Heat collection efficiency	44.2%	Annual solar efficiency		13.7%
Power cycle efficiency	38.0%	Plant capacity		26.0%
Parasitic efficiency	90.2%	Solar capacity		26.0%
Solar-to-electric net efficiency	15.1%	Plant efficiency (Back-up Mode)		53.5%
Levelised Electricity Cost calculations				
Net electricity by solar			68,328	MWhe/yr
Net electricity by fuel			-	MWhe/yr
Net electricity to grid			68,328	MWhe/yr
Solar share			100.0%	
Full load hours - total			2,278	h/yr
Full load hours - solar			2,278	h/yr
Annual fuel use			-	GJ/yr
Annual fuel cost			-	'000 USD
Annual O&M cost			668	'000 USD
Levelised Electricity Cost (entire plant)			**148.49**	**USD/MWh**
Capital cost fraction			138.71	USD/MWh
Fuel cost fraction			-	USD/MWh
O&M cost fraction			9.78	USD/MWh
Solar LEC calculations				
LEC for base case plant of equivalent power; type:		Combined Cycle	N/A	USD/MWh
Capital cost fraction			N/A	USD/MWh
Fuel cost fraction			N/A	USD/MWh
O&M cost fraction			N/A	USD/MWh
LEC (solar only component)			**148.49**	**USD/MWh**
Avoided emissions calculations				
Electricity production by fuel over lifetime			-	MWhe
Electricity production - total over lifetime			1,708,200	MWhe
Emissions over lifetime (STPP)			-	t CO_2
Emissions over lifetime (Base case)		Combined Cycle	571,043	t CO_2
Avoided emissions (over lifetime)			**571,043**	t CO_2
Avoided emissions (annual)			**22,842**	t CO_2 per year
Avoidance cost (w/o grant) against base case			**138.12**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**6**		**30 MW**	**Tower**	**Rankine**
Net capacity	30 MW		Solar field	n/a	m^2
Solar capacity	30 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	126,276	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	4,209	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	46.8%	Annual solar efficiency			14.9%
Power cycle efficiency	40.0%	Plant capacity			50.0%
Parasitic efficiency	84.0%	Solar capacity			44.0%
Solar-to-electric net efficiency	15.7%	Plant efficiency (Back-up Mode)			31.1%
Levelised Electricity Cost calculations					
Net electricity by solar				115,632	MWhe/yr
Net electricity by fuel				15,768	MWhe/yr
Net electricity to grid				131,400	MWhe/yr
Solar share				88.0%	
Full load hours - total				4,380	h/yr
Full load hours - solar				3,854	h/yr
Annual fuel use				182,523	GJ/yr
Annual fuel cost				208.08	'000 USD
Annual O&M cost				2,904	'000 USD
Levelised Electricity Cost (entire plant)				**139.17**	**USD/MWh**
Capital cost fraction				115.48	USD/MWh
Fuel cost fraction				1.58	USD/MWh
O&M cost fraction				22.10	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		42.96	USD/MWh
Capital cost fraction				23.72	USD/MWh
Fuel cost fraction				11.93	USD/MWh
O&M cost fraction				7.31	USD/MWh
LEC (solar only component)				**152.28**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				394,200	MWhe
Electricity production - total over lifetime				3,285,000	MWhe
Emissions over lifetime (STPP)				391,969	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		2,953,062	t CO_2
Avoided emissions (over lifetime)				**2,561,093**	t CO_2
Avoided emissions (annual)				**102,444**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**49.31**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	7		30 MW	Tower	ISCCS
Net capacity	30 MW		Solar field	n/a	m^2
Solar capacity	30 MW		Fuel type	Gas	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	110,645	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	2.63	Fixed charge rate		12.02%	
Unit cost (USD/kW)	3,688	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	46.8%	Annual solar efficiency			15.7%
Power cycle efficiency	40.0%	Plant capacity			47.0%
Parasitic efficiency	88.5%	Solar capacity			47.0%
Solar-to-electric net efficiency	16.6%	Plant efficiency (Back-up Mode)			53.5%
Levelised Electricity Cost calculations					
Net electricity by solar				123,516	MWhe/yr
Net electricity by fuel				-	MWhe/yr
Net electricity to grid				123,516	MWhe/yr
Solar share				100.0%	
Full load hours - total				4,117	h/yr
Full load hours - solar				4,117	h/yr
Annual fuel use				-	GJ/yr
Annual fuel cost				-	'000 USD
Annual O&M cost				1,680	'000 USD
Levelised Electricity Cost (entire plant)				**121.25**	**USD/MWh**
Capital cost fraction				107.65	USD/MWh
Fuel cost fraction				-	USD/MWh
O&M cost fraction				13.60	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Combined Cycle		N/A	USD/MWh
Capital cost fraction				N/A	USD/MWh
Fuel cost fraction				N/A	USD/MWh
O&M cost fraction				N/A	USD/MWh
LEC (solar only component)				**121.25**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				-	MWhe
Electricity production - total over lifetime				3,087,900	MWhe
Emissions over lifetime (STPP)				-	t CO_2
Emissions over lifetime (Base case)		Combined Cycle		1,032,271	t CO_2
Avoided emissions (over lifetime)				**1,032,271**	t CO_2
Avoided emissions (annual)				**41,291**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**107.19**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**8**	**100 MW**	**Trough**	**ISCCS**
Net capacity	100 MW	Solar field	n/a	m^2
Solar capacity	100 MW	Fuel type	Gas	
Summary of base case parameters				
Project cost w/o tax ('000 USD) *	179,265	Expected lifetime	25	years
Grant for non-conventional fraction	-	Annual discount rate	10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate	1.0%	
Fuel price (USD per GJ)	2.63	Fixed charge rate	12.02%	
Unit cost (USD/kW)	1,793	CO_2 credits	-	USD/tonne
Efficiencies				
Heat collection efficiency	46.0%	Annual solar efficiency		14.6%
Power cycle efficiency	39.0%	Plant capacity		26.2%
Parasitic efficiency	90.2%	Solar capacity		26.2%
Solar-to-electric net efficiency	16.2%	Plant efficiency (Back-up Mode)		53.5%
Levelised Electricity Cost calculations				
Net electricity by solar			229,512	MWhe/yr
Net electricity by fuel			-	MWhe/yr
Net electricity to grid			229,512	MWhe/yr
Solar share			100.0%	
Full load hours - total			2,295	h/yr
Full load hours - solar			2,295	h/yr
Annual fuel use			-	GJ/yr
Annual fuel cost			-	'000 USD
Annual O&M cost			1,151	'000 USD
Levelised Electricity Cost (entire plant)			**98.87**	**USD/MWh**
Capital cost fraction			93.86	USD/MWh
Fuel cost fraction			-	USD/MWh
O&M cost fraction			5.02	USD/MWh
Solar LEC calculations				
LEC for base case plant of equivalent power; type:		Combined Cycle	N/A	USD/MWh
Capital cost fraction			N/A	USD/MWh
Fuel cost fraction			N/A	USD/MWh
O&M cost fraction			N/A	USD/MWh
LEC (solar only component)			**98.87**	**USD/MWh**
Avoided emissions calculations				
Electricity production by fuel over lifetime			-	MWhe
Electricity production - total over lifetime			5,737,800	MWhe
Emissions over lifetime (STPP)			-	t CO_2
Emissions over lifetime (Base case)		Combined Cycle	1,918,120	t CO_2
Avoided emissions (over lifetime)			**1,918,120**	t CO_2
Avoided emissions (annual)			**76,725**	t CO_2 per year
Avoidance cost (w/o grant) against base case			**93.46**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**9**		**200 MW**	**Trough**	**Rankine**
Net capacity	200 MW		Solar field	n/a	m^2
Solar capacity	200 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	349,350	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	1,747	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	46.0%	Annual solar efficiency			14.0%
Power cycle efficiency	39.0%	Plant capacity			50.0%
Parasitic efficiency	83.6%	Solar capacity			25.1%
Solar-to-electric net efficiency	15.0%	Plant efficiency (Back-up Mode)			34.1%
Levelised Electricity Cost calculations					
Net electricity by solar				439,752	MWhe/yr
Net electricity by fuel				436,248	MWhe/yr
Net electricity to grid				876,000	MWhe/yr
Solar share				50.2%	
Full load hours - total				4,380	h/yr
Full load hours - solar				2,199	h/yr
Annual fuel use				4,605,551	GJ/yr
Annual fuel cost				5,250.33	'000 USD
Annual O&M cost				6,999	'000 USD
Levelised Electricity Cost (entire plant)				**61.91**	**USD/MWh**
Capital cost fraction				47.92	USD/MWh
Fuel cost fraction				5.99	USD/MWh
O&M cost fraction				7.99	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		42.96	USD/MWh
Capital cost fraction				23.72	USD/MWh
Fuel cost fraction				11.93	USD/MWh
O&M cost fraction				7.31	USD/MWh
LEC (solar only component)				**80.71**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				10,906,200	MWhe
Electricity production - total over lifetime				21,900,000	MWhe
Emissions over lifetime (STPP)				9,890,420	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		19,687,081	t CO_2
Avoided emissions (over lifetime)				**9,796,661**	t CO_2
Avoided emissions (annual)				**391,866**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**35.66**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**10**		**200 MW**	**Trough**	**Rankine**
Net capacity	200 MW		Solar field	n/a	m^2
Solar capacity	200 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	310,250	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	1,551	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	51.9%	Annual solar efficiency			16.2%
Power cycle efficiency	40.0%	Plant capacity			50.0%
Parasitic efficiency	86.7%	Solar capacity			26.4%
Solar-to-electric net efficiency	18.0%	Plant efficiency (Back-up Mode)			34.1%
Levelised Electricity Cost calculations					
Net electricity by solar				462,528	MWhe/yr
Net electricity by fuel				413,472	MWhe/yr
Net electricity to grid				876,000	MWhe/yr
Solar share				52.8%	
Full load hours - total				4,380	h/yr
Full load hours - solar				2,313	h/yr
Annual fuel use				4,365,100	GJ/yr
Annual fuel cost				4,976.21	'000 USD
Annual O&M cost				5,585	'000 USD
Levelised Electricity Cost (entire plant)				**54.62**	**USD/MWh**
Capital cost fraction				42.56	USD/MWh
Fuel cost fraction				5.68	USD/MWh
O&M cost fraction				6.38	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		42.96	USD/MWh
Capital cost fraction				23.72	USD/MWh
Fuel cost fraction				11.93	USD/MWh
O&M cost fraction				7.31	USD/MWh
LEC (solar only component)				**65.04**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				10,336,800	MWhe
Electricity production - total over lifetime				21,900,000	MWhe
Emissions over lifetime (STPP)				9,374,053	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		19,687,081	t CO_2
Avoided emissions (over lifetime)				**10,313,029**	t CO_2
Avoided emissions (annual)				**412,521**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**30.08**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**11**		**200 MW**	**Trough**	**Rankine**
Net capacity	200 MW		Solar field	n/a	m^2
Solar capacity	200 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	421,770	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	2,109	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	53.6%	Annual solar efficiency			16.6%
Power cycle efficiency	40.0%	Plant capacity			50.0%
Parasitic efficiency	90.2%	Solar capacity			50.0%
Solar-to-electric net efficiency	19.3%	Plant efficiency (Back-up Mode)			34.1%
Levelised Electricity Cost calculations					
Net electricity by solar				876,000	MWhe/yr
Net electricity by fuel				-	MWhe/yr
Net electricity to grid				876,000	MWhe/yr
Solar share				100.0%	
Full load hours - total				4,380	h/yr
Full load hours - solar				4,380	h/yr
Annual fuel use				-	GJ/yr
Annual fuel cost				-	'000 USD
Annual O&M cost				3,574	'000 USD
Levelised Electricity Cost (entire plant)				**61.94**	**USD/MWh**
Capital cost fraction				57.86	USD/MWh
Fuel cost fraction				-	USD/MWh
O&M cost fraction				4.08	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		N/A	USD/MWh
Capital cost fraction				N/A	USD/MWh
Fuel cost fraction				N/A	USD/MWh
O&M cost fraction				N/A	USD/MWh
LEC (solar only component)				**61.94**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				-	MWhe
Electricity production - total over lifetime				21,900,000	MWhe
Emissions over lifetime (STPP)				-	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		19,687,081	t CO_2
Avoided emissions (over lifetime)				**19,687,081**	t CO_2
Avoided emissions (annual)				**787,483**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**21.42**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	12		100 MW	Tower	ISCCS
Net capacity	100 MW		Solar field	n/a	m^2
Solar capacity	100 MW		Fuel type	Gas	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	212,925	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	2.63	Fixed charge rate		12.02%	
Unit cost (USD/kW)	2,129	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	49.3%	Annual solar efficiency			18.5%
Power cycle efficiency	43.0%	Plant capacity			44.7%
Parasitic efficiency	0.0%	Solar capacity			44.7%
Solar-to-electric net efficiency	0.0%	Plant efficiency (Back-up Mode)			53.5%
Levelised Electricity Cost calculations					
Net electricity by solar				391,134	MWhe/yr
Net electricity by fuel				-	MWhe/yr
Net electricity to grid				391,134	MWhe/yr
Solar share				100.0%	
Full load hours - total				3,911	h/yr
Full load hours - solar				3,911	h/yr
Annual fuel use				-	GJ/yr
Annual fuel cost				-	'000 USD
Annual O&M cost				1,995	'000 USD
Levelised Electricity Cost (entire plant)				**70.52**	**USD/MWh**
Capital cost fraction				65.42	USD/MWh
Fuel cost fraction				-	USD/MWh
O&M cost fraction				5.10	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Combined Cycle		N/A	USD/MWh
Capital cost fraction				N/A	USD/MWh
Fuel cost fraction				N/A	USD/MWh
O&M cost fraction				N/A	USD/MWh
LEC (solar only component)				**70.52**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				-	MWhe
Electricity production - total over lifetime				9,778,350	MWhe
Emissions over lifetime (STPP)				-	t CO_2
Emissions over lifetime (Base case)		Combined Cycle		3,268,857	t CO_2
Avoided emissions (over lifetime)				**3,268,857**	t CO_2
Avoided emissions (annual)				**130,754**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**65.14**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**13**		**100 MW**	**Tower**	**Rankine**
Net capacity	100 MW		Solar field	n/a	m^2
Solar capacity	100 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	244,120	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	2,441	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	0.0%	Annual solar efficiency			17.6%
Power cycle efficiency	0.0%	Plant capacity			50.0%
Parasitic efficiency	0.0%	Solar capacity			42.2%
Solar-to-electric net efficiency	0.0%	Plant efficiency (Back-up Mode)			34.1%
Levelised Electricity Cost calculations					
Net electricity by solar				369,234	MWhe/yr
Net electricity by fuel				68,766	MWhe/yr
Net electricity to grid				438,000	MWhe/yr
Solar share				84.3%	
Full load hours - total				4,380	h/yr
Full load hours - solar				3,692	h/yr
Annual fuel use				725,975	GJ/yr
Annual fuel cost				827.61	'000 USD
Annual O&M cost				4,468	'000 USD
Levelised Electricity Cost (entire plant)				**79.07**	**USD/MWh**
Capital cost fraction				66.98	USD/MWh
Fuel cost fraction				1.89	USD/MWh
O&M cost fraction				10.20	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		42.96	USD/MWh
Capital cost fraction				23.72	USD/MWh
Fuel cost fraction				11.93	USD/MWh
O&M cost fraction				7.31	USD/MWh
LEC (solar only component)				**85.79**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				1,719,150	MWhe
Electricity production - total over lifetime				10,950,000	MWhe
Emissions over lifetime (STPP)				1,559,032	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		9,843,541	t CO_2
Avoided emissions (over lifetime)				**8,284,509**	t CO_2
Avoided emissions (annual)				**331,380**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**29.47**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**14**		**100 MW**	**Tower**	**Rankine**
Net capacity	100 MW		Solar field	n/a	m^2
Solar capacity	100 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	212,925	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	2,129	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	0.0%	Annual solar efficiency			18.5%
Power cycle efficiency	0.0%	Plant capacity			50.0%
Parasitic efficiency	0.0%	Solar capacity			44.7%
Solar-to-electric net efficiency	0.0%	Plant efficiency (Back-up Mode)			34.1%
Levelised Electricity Cost calculations					
Net electricity by solar				391,134	MWhe/yr
Net electricity by fuel				46,866	MWhe/yr
Net electricity to grid				438,000	MWhe/yr
Solar share				89.3%	
Full load hours - total				4,380	h/yr
Full load hours - solar				3,911	h/yr
Annual fuel use				494,773	GJ/yr
Annual fuel cost				564.04	'000 USD
Annual O&M cost				2,234	'000 USD
Levelised Electricity Cost (entire plant)				**64.81**	**USD/MWh**
Capital cost fraction				58.42	USD/MWh
Fuel cost fraction				1.29	USD/MWh
O&M cost fraction				5.10	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		42.96	USD/MWh
Capital cost fraction				23.72	USD/MWh
Fuel cost fraction				11.93	USD/MWh
O&M cost fraction				7.31	USD/MWh
LEC (solar only component)				**67.42**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				1,171,650	MWhe
Electricity production - total over lifetime				10,950,000	MWhe
Emissions over lifetime (STPP)				1,062,525	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		9,843,541	t CO_2
Avoided emissions (over lifetime)				**8,781,016**	t CO_2
Avoided emissions (annual)				**351,241**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**24.25**	**USD/t CO_2**

* - cost includes discount in developing countries

Levelised Energy Cost (LEC) Calculations - Base case

Economic analysis:	**15**		**200 MW**	**Tower**	**Rankine**
Net capacity	200 MW		Solar field	n/a	m^2
Solar capacity	200 MW		Fuel type	Coal	
Summary of base case parameters					
Project cost w/o tax ('000 USD) *	312,120	Expected lifetime		25	years
Grant for non-conventional fraction	-	Annual discount rate		10.0%	
Carbon credit ('000 USD)	-	Annual insurance rate		1.0%	
Fuel price (USD per GJ)	1.14	Fixed charge rate		12.02%	
Unit cost (USD/kW)	1,561	CO_2 credits		-	USD/tonne
Efficiencies					
Heat collection efficiency	0.0%	Annual solar efficiency			20.3%
Power cycle efficiency	0.0%	Plant capacity			50.0%
Parasitic efficiency	0.0%	Solar capacity			44.7%
Solar-to-electric net efficiency	0.0%	Plant efficiency (Back-up Mode)			34.1%
Levelised Electricity Cost calculations					
Net electricity by solar				782,268	MWhe/yr
Net electricity by fuel				93,732	MWhe/yr
Net electricity to grid				876,000	MWhe/yr
Solar share				89.3%	
Full load hours - total				4,380	h/yr
Full load hours - solar				3,911	h/yr
Annual fuel use				989,546	GJ/yr
Annual fuel cost				1,128.08	'000 USD
Annual O&M cost				4,468	'000 USD
Levelised Electricity Cost (entire plant)				**49.20**	**USD/MWh**
Capital cost fraction				42.82	USD/MWh
Fuel cost fraction				1.29	USD/MWh
O&M cost fraction				5.10	USD/MWh
Solar LEC calculations					
LEC for base case plant of equivalent power; type:		Coal Rankine		42.96	USD/MWh
Capital cost fraction				23.72	USD/MWh
Fuel cost fraction				11.93	USD/MWh
O&M cost fraction				7.31	USD/MWh
LEC (solar only component)				**49.95**	**USD/MWh**
Avoided emissions calculations					
Electricity production by fuel over lifetime				2,343,300	MWhe
Electricity production - total over lifetime				21,900,000	MWhe
Emissions over lifetime (STPP)				2,125,050	t CO_2
Emissions over lifetime (Base case)		Coal Rankine		19,687,081	t CO_2
Avoided emissions (over lifetime)				**17,562,031**	t CO_2
Avoided emissions (annual)				**702,481**	t CO_2 per year
Avoidance cost (w/o grant) against base case				**17.77**	**USD/t CO_2**

* - cost includes discount in developing countries